AR89

COMPTON
PETROLEUM CORPORATION

2007 Annual Report

A NATURAL GAS RESOURCE COMPANY

Compton's Callum/Cowley Foothills Gas Plant

COMPTON
PETROLEUM CORPORATION

"Compton Petroleum Corporation is an independent, public company actively engaged in the exploration for and development and production of natural gas, natural gas liquids, and crude oil in western Canada. Our activities are focused primarily in the Deep Basin fairway in the province of Alberta, in the Western Canada Sedimentary Basin. Our growth and reserve base results predominantly from our exploration and development drilling programs. Compton's shares are listed on the Toronto Stock Exchange under the symbol CMT and on the New York Stock Exchange under the symbol CMZ."

Contents

Annual Meeting Information

The Annual General Meeting of Shareholders will be held on Monday, May 12, 2008 at 3:00 p.m. in the Historical Ballroom of the Calgary Chamber of Commerce, 517 - Centre Street South, Calgary, Alberta, Canada.

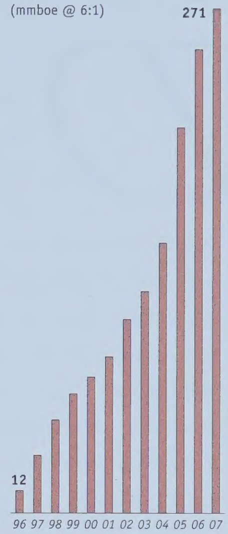
Financial Highlights

($000s, except where noted)	2007	2006	2005
Total revenue	**$ 500,987**	$ 540,837	$ 564,241
Adjusted cash flow from operations	**$ 196,194**	$ 256,305	$ 278,112
Per share: basic *($)*	**$ 1.52**	$ 2.01	$ 2.21
diluted *($)*	**$ 1.48**	$ 1.92	$ 2.11
Net earnings	**$ 129,266**	$ 127,426	$ 81,326
Per share: basic *($)*	**$ 1.00**	$ 1.00	$ 0.65
diluted *($)*	**$ 0.98**	$ 0.95	$ 0.62
Capital expenditures	**$ 385,532**	$ 491,511	$ 483,700
Corporate debt, net	**$ 871,403**	$ 875,548	$ 597,656
Shareholders' equity	**$ 869,956**	$ 734,124	$ 596,336
Share Price			
Close	**$ 9.14**	$ 10.65	$ 17.10
Average volume traded	**485,027**	545,489	736,416

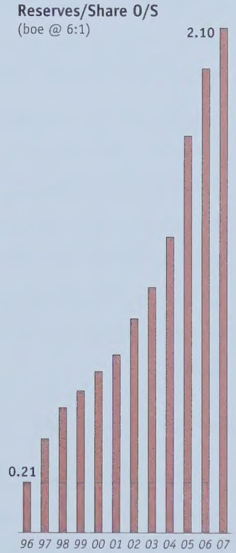
Operational Highlights

	2007	2006	2005
Average daily production volumes			
Natural gas *(mmcf/d)*	**145**	142	131
Liquids (light oil & ngls) *(bbls/d)*	**7,166**	9,516	7,646
Total oil equivalent *(boe/d)*	**31,326**	33,187	29,424
Realized prices			
Natural gas *(per mcf)*	**$ 6.33**	$ 6.32	$ 8.36
Liquids *($/bbl)*	**$ 62.28**	$ 59.09	$ 56.47
Total oil equivalent *($/boe)*	**$ 43.82**	$ 44.65	$ 52.54
Field operating netback *($/boe)*	**$ 26.54**	$ 28.17	$ 31.46
Cash flow netback *($/boe)*	**$ 18.25**	$ 21.53	$ 25.76
Undeveloped land			
Gross acres	**1,121,130**	980,179	971,317
Net acres	**893,462**	798,192	738,954
Average working interest	**80%**	81%	76%
Reserves			
Proved *(mboe)*	**149,564**	147,218	125,960
Proved + probable *(mboe)*	**270,819**	248,755	206,671
Reserve life index *(proved)*	**13**	12	12
Reserve life index *(P+P)*	**23**	21	19

Proved + Probable Reserves
(mmboe @ 6:1)



Proved + Probable Reserves/Share O/S
(boe @ 6:1)



p 1

Report to our Shareholders

2007 President's Message

During 2007, Compton experienced very positive technical and operational results complemented by a solid financial performance, notwithstanding significantly reduced natural gas prices during the latter half of the year that affected the industry as a whole. We drilled 322 wells with a 97% success rate, achieved our production targets for the year, and once again, substantially grew our reserve base at competitive finding and development costs. Success achieved during the latter half of the year utilizing multi-stage fracing combined with horizontal wells has the potential to enhance dramatically our upside and the production profiles in our unconventional resource plays. Average production for the year was 31,326 boe/d.

I am also very pleased to report that despite lower year end natural gas prices, Compton's 2007 proved plus probable reserves grew by nine percent and are now valued in excess of $3.4 billion dollars, using a discount rate of eight percent. Compton added 2.3 million boe proved and 22 million boe proved plus probable reserve additions, after production and asset sales, for total proved plus probable reserves of 271 million boe as at December 31, 2007. This number equates to 2.10 boe per common share outstanding, versus 1.93 boe from last year, also an increase of 9%. Importantly, we achieved this growth at a highly competitive cost of $9.95 per boe on a proved plus probable basis, excluding future capital, or $12.86 per boe (P+P), including future capital.

SETTING THE STAGE

Our primary goal for 2007 was to set the stage and put all of the elements in place for Compton to execute on its three year strategic plan. This plan emphasized increasingly larger well counts to enable the Company to realize on our large resource potential in a timely and capital efficient manner. Our original three year strategic plan as presented in June 2007 anticipated the Company drilling 600 wells in 2008, 800 wells in 2009, and 1,000 wells in 2010. This plan was based on AECO $8.00/mcf natural gas in 2008 and AECO $9.00/mcf natural gas for 2009 and thereafter. When natural gas prices fell below $6.50/mcf for a prolonged period of time, we adjusted our strategic plan. Based on lower natural gas prices, we plan to drill 350, 550, and 700 wells in 2008, 2009, and 2010, respectively. The revised plan will be funded by cash flow, the disposition of non-core properties, and the use of our strong bank credit capacity to result in 16% to 20% annual production growth and approximately 30% average cash flow growth assuming AECO $6.95/mcf in 2008 and AECO $7.50 in subsequent years.

At the time of writing this letter, we've seen a strengthening in natural gas prices. With consensus natural gas price forecasts now moving above $8.00/mcf for 2008 and $9.00/mcf for 2009, we are in an even stronger position to deliver on and expand our drilling targets. At these gas prices, Compton's debt to trailing cash flow would be at a very manageable level of approximately 2 to 1.

To set the stage for the success of our strategic plan, we had a number of key objectives to accomplish in 2007:

- ensure Compton had the financial strength required to accelerate our drilling programs;
- add to our already strong technical and professional teams;
- focus on cost control;
- establish an efficient resource manufacturing and processing model for our unconventional shallow gas, optimizing use of existing and new technology;
- take full advantage of the new downspacing and commingling regulations; and
- optimize drilling technologies used in our deep gas drilling.

2007 — ACHIEVEMENT OF OUR KEY OBJECTIVES

While this past year has challenged Canadian oil and gas producers with weak natural gas prices, widening AECO to NYMEX differentials, anticipated Alberta royalty structure changes, and the strengthening Canadian dollar relative to the U.S. dollar, Compton has worked hard to thrive in and take advantage of opportunities inherent in this downturn. In 2007, AECO daily natural gas prices averaged $6.43/mcf, while oil prices climbed steadily throughout the year, reaching a new historic high, well above the $90.00/bbl mark during the fourth quarter. Recognizing the value a sale of our Peace River Arch conventional light oil assets would garner, we sold Worsley for $270 million, and we are in the process of selling our other significant oil property, Cecil. We also plan to sell two other non-core assets, Bigoray and Thornbury, in the first half of 2008 for total estimated proceeds of $250 million.

Additionally, we took advantage of the lower valuations for gas-weighted assets and closed three core area acquisitions for a total of $140 million. These new assets fit perfectly with our existing natural gas resource plays and will make a meaningful contribution to our portfolio of opportunities, while the sale of Worsley, combined with our other non-core property divestments and aggressive hedging strategy, bolsters our financial strength.

Our financial strength has been further enhanced by the foreign exchange contracts relating to our U.S.$450 million Senior Notes that we completed during the fourth quarter of 2007. These contracts effectively fix the Canadian dollar repayment amount of the Senior Notes at $436 million and crystallize an unrealized foreign exchange gain of approximately $91.7 million.

Another critical achievement for Compton in 2007 included the addition of 37 new people to our technical and professional teams. We structured our teams and operations into three core areas, all focused on natural gas. We have a Shallow Gas team that oversees our Plains Belly River and Edmonton Group resource play, a Deep Basin Gas team that manages our deep gas resource plays at Niton, Caroline, and Hooker, and a Foothills team, responsible for activity at our high impact exploration play at Callum and Cowley. We've added two people to our executive team. Rob Symonds, P.Eng, has joined Compton as Vice President, Foothills & Corporate Development. Gary Follensbee, P.Eng., has been appointed Vice President, Engineering Exploitation.

The next three objectives that we had to accomplish in 2007 to set the stage for large well counts were reducing costs, establishing a manufacturing and processing resource model that optimizes use of existing and new technology, and taking advantage of the new downspacing and commingling regulations. As part of our efforts to establish a repeatable, cost effective, and efficient resource manufacturing and processing model in 2007, we focused on drilling our shallow gas wells close to infrastructure, as well as utilizing coiled tubing and slant rigs and the best equipment and crews available. Wherever possible, we drilled multiple well projects for increased efficiency. This strategy assisted with the optimization of our drilling program to take advantage of the new downspacing rules and to increase our operating efficiencies. Additionally, we reduced our shallow gas spud to rig release and rig release to on-stream times to 2.8 days and 99 days, respectively. These elements are essential to the successful establishment of our efficient resource manufacturing and processing model.

"In 2007, Compton added 2.3 million boe proved and 22 million boe proved plus probable reserve additions, after production and asset sales, for total proved plus probable reserves of 271 million boe as at December 31, 2007."

Report to our Shareholders

> "In 2008, we plan to invest $410 million to drill 350 wells that are expected to deliver between 16% and 20% year over year average production growth. We expect 2008 average production to range between 36,000 and 37,000 boe/d."

IMPACT OF NEW TECHNOLOGY

Compton was one of the Canadian industry leaders in the adaptation of horizontal drilling for unconventional natural gas in 2007. Last year, we drilled nine horizontal natural gas wells, eight of which used multi-stage fracing technology. These eight wells were all drilled at our Niton deep gas resource play. We experienced significant drilling and production success on our Rock Creek tight gas formations using multi-stage fracing to isolate sections of the horizontal well.

By way of example, in March 2008, Compton successfully completed the first horizontal well in southern Alberta at Hooker targeting the Basal Quartz formation utilizing multi-stage fracing technology. The well at 9-17-17-29W4 was drilled with a 700 metre horizontal leg and it flow tested at six mmcf/d. At Niton in early 2008, we drilled three additional horizontal wells. The first well tested 3.0 mmcf/d and the well at 4-27-52-17W5 completed at the end of February flow tested at 11 mmcf/d. The third well is scheduled to be completed in March. The cost to drill, complete, and tie-in these horizontal wells, including a five stage frac, is in the range of $3.8 to $4.2 million dollars. As a result of the limited production history, a definitive standardized production profile for these wells has not yet been determined. However, we expect high initial decline rates in the first year of production typical of tight sandstone formations. Assuming a production profile similar to that of a vertical well that declines 50% to 60% in the first year and 8% to 12% per year thereafter, the Niton well at 4-27-52-17W5 would pay-out in four months while the Hooker well at 9-17-17-29W4 would pay-out in seven to eight months, assuming a natural gas price of $8.00/mcf. By comparison, a Hooker vertical well with a cost of $1.8 million and an initial production rate of 1.8 mmcf/d would pay out in 13 to 14 months.

We believe that this technology is applicable not only to our Niton and Caroline plays in central Alberta, but also to our Hooker, Callum/Cowley, and our Plains Belly River shallow gas resource play in southern Alberta. The application of this technology throughout all of our natural gas resource plays should have a dramatic impact on Compton's production, cash flow, and value.

2008

In 2008, we plan to spend $410 million to drill 350 wells that are expected to deliver between 16% and 20% year over year average production growth. We expect 2008 average production to range between 36,000 and 37,000 boe/d. Our planned 2008 activities are weighted towards the latter half of the year during which we plan to incur approximately 60% of our budgeted expenditures. Compton's 2008 budget is set to grow our asset and production bases appropriately, while maintaining capital discipline.

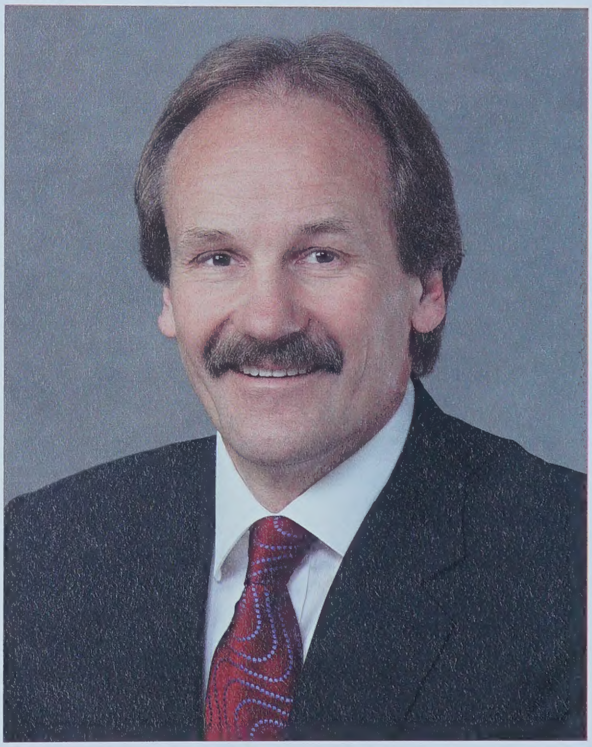
In 2008, we plan to drill 350 wells, of which 30 are currently planned as horizontal wells. Of the total wells planned for 2008, 70 will target the deeper formations in our Niton, Caroline, Hooker, and Callum/Cowley properties where we have had excellent results to date, particularly with our horizontal multi-stage frac drilling.

We have also planned 275 wells in our southern Alberta core area targeting the shallow Belly River formation. These wells are very low risk with attractive cost structures, and we have high graded our well site selections to focus on locations where returns are most favourable. The 275 wells targeting the Belly River formation include 10 horizontal test wells. Importantly, infrastructure has been expanded in this area to accommodate rapid production growth.

As we enter 2008, it is noteworthy that in response to a formal request by one of our significant shareholders Compton's Board of Directors has determined to undertake a formal review process of the company's business plans and strategic alternatives for enhancing shareholder value.

2007 marked another exciting and challenging year in the energy industry. I am very pleased with the continued dedication of all of Compton's employees, and I would like to thank our employees for their commitment and enthusiasm. Finally, I'd like to thank our Board of Directors for their strong support of and confidence in Compton's ability to deliver enhanced value to all shareholders.

We have made significant improvements in our project execution strategies. We have a highly enviable suite of assets in our portfolio, assets that promise huge upside to all of our shareholders. Delivering the best possible results from those assets to our shareholders is our primary goal.

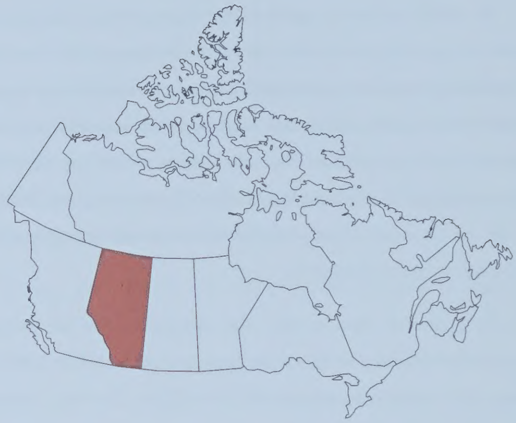


Sincerely,

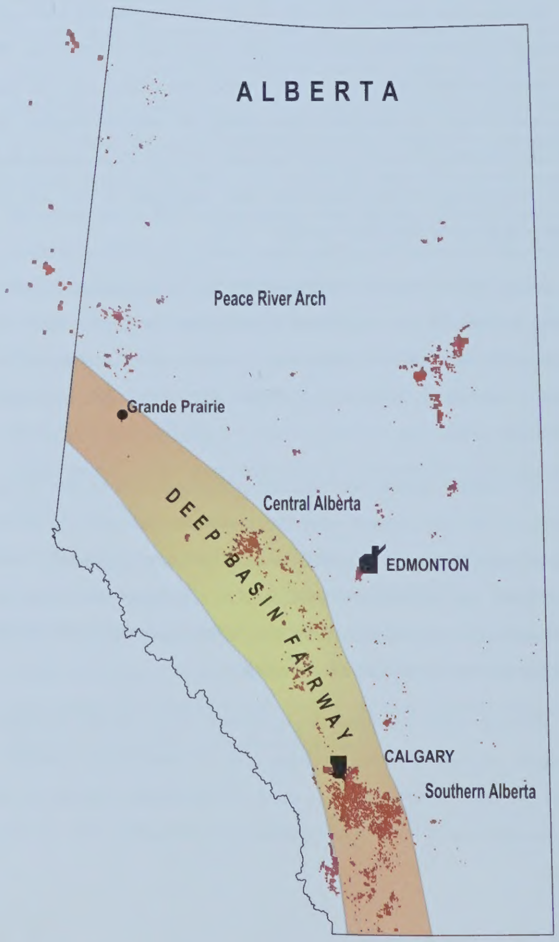
ERNIE SAPIEHA
President & Chief Executive Officer

March 24, 2008

Review of Operations



"Compton engages in oil and gas exploration and development in the Western Canada Sedimentary Basin of Alberta, Canada. Our focus is on the Deep Basin portion of the Basin, which extends from Northwest Alberta and British Columbia to the United States border. In this large geographical region, we pursue two types of resource plays. A shallow gas resource play, targeting the Plains Belly River and overlying Edmonton Horseshoe Canyon zones, and the three deep gas plays that include the Basal Quartz sands at Hooker, the Gething/Rock Creek sands at Niton and Caroline in central Alberta, and the Foothills stacked, thrusted Upper Cretaceous Belly River play at Callum in the south."



SHALLOW GAS

The Plains Belly River and overlying Edmonton Horseshoe Canyon shallow gas zones cover more than 1,200 sections of Compton held land in southern Alberta. The entire 900 metre gas-charged section is comprised of multiple Belly River sands, silts, shales, and coals, overlain by the Edmonton/Horseshoe Canyon Coals that similarly include sands, silts, and shales. In 2007 we drilled a total of 226 wells through the Edmonton Horseshoe Canyon Group targeting the Belly River section. Going forward, we will focus on downspacing, development drilling, and recompletions in order to establish a resource manufacturing and processing model designed to maximize production.

PLAINS BELLY RIVER AND EDMONTON COAL BED METHANE

At December 31, 2007, we were producing approximately 55 mmcf/d from 630 Belly River and Edmonton coal bed methane wells. With 1,200 sections of land, at four wells per section automatic downspacing, this translates to a significant multi-year, low risk drilling inventory on which to grow our company.

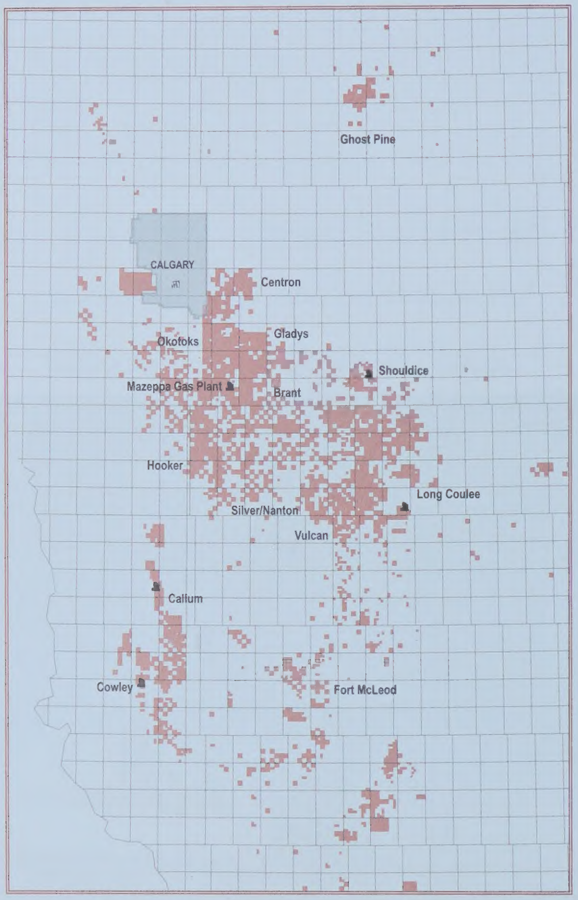
During 2007, we took full advantage of the four well per section reduced spacing initiative for our Belly River drilling program. Wherever possible, our shallow gas wells were drilled in batches in areas close to existing infrastructure. This initiative enabled us to significantly reduce our 2007 spud to rig release and rig release to on-stream times to 2.8 days and 99 days, respectively. Drilling results at our southern Alberta Belly River play were 100% successful in 2007, and we made particularly notable advances in the Brant, south Hooker, Ghost Pine, and Vulcan areas. Using our 1,200 km^2 of proprietary 3D seismic, coupled with detailed geological mapping, has allowed us to model the Belly River sands for consistent, repeatable success.

At Brant, our 3-5-17-27W4M compressor station became fully operational in November 2007, providing us the requisite horsepower needed to bring on eight new 100% owned Belly River wells. These wells were producing a combined four mmcf/d at year end. The average production rate of these wells is approximately double the 30 day initial production rate of a typical Belly River well. Our 2007 drilling targeted longer term producing wells such as Compton Brant 00/07-05-017-27W4M/0 and Compton Silver 00/13-32-016-28W4M/2. These two wells are producing 570 and 860 mcf/d, respectively. In 2008, we will aggressively follow up similar trends into south Hooker and south Brant.

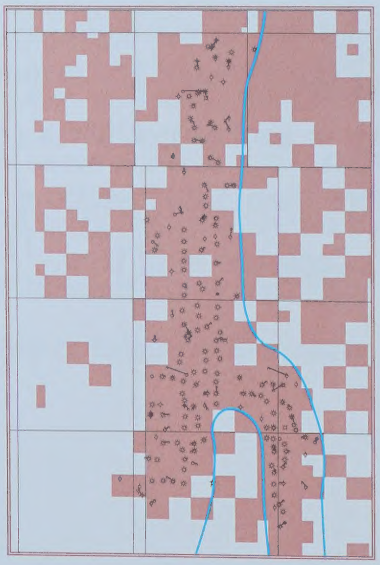
Compton well site – Gladys 14-32-20-27W5M

> "Our shallow gas resource plays in southern Alberta cover more than 1,200 sections of Compton held land."

Review of Operations



Southern Alberta – Shallow Gas



Southern Alberta – Hooker Deep Gas

In the Ghost Pine area, we expanded our 15-11-30-23W4M compressor station from eight to 12 mmcf/d in 2007. A total of 62 Belly River and Horseshoe Canyon coal wells are currently producing 12 mmcf/d at Ghost Pine. We have 14 standing gas wells that are scheduled to be tied-in in the first quarter 2008. We have recently reprocessed our 3D seismic in this area, and in 2008 we plan to use this seismic to replicate the Ghost Pine Belly River gas well 02/07-10-030-23W4M, which had an initial production rate of 1,300 mcf/d, and the 00/05-01-030-23W4/4 Coal Bed Methane gas well, which had an initial production rate of 74 mcf/d.

Finally, further south in the Vulcan area, we placed five Belly River gas wells drilled by Stylus Energy on production in late 2007. In aggregate, these wells were placed on production at 2.2 mmcf/d. These wells are the southernmost Belly River gas wells producing in Alberta.

Our total compression capacity for southern Alberta low pressure gas is 95 mmcf/d. Compton had 27,000 horsepower of installed compression dedicated to the play installed and running at year end 2007.

In 2008, we plan to drill 275 Belly River wells, focusing specifically on the top tier prospects identified by our technical teams. We have allocated approximately $180 million in our budget to this area, with $5 million ear-marked specifically to continue with identification of well locations and licensing such that as industry conditions improve, we can readily ramp-up activity. We estimate that roughly 40% of our 2008 Belly River wells drilled in the latter part of the year will not come on production until early 2009 and will, as a result, take full advantage of the lower shallow gas royalty rates effective for 2009.

Our 2008 southern Alberta plans also include an eight well per section pilot project. Additionally, and following on one Deep Basin deeper target success, we will use extended reach drilling with multi-stage fracturing techniques.

DEEP BASIN

Compton has two Deep Basin gas plays: the Basal Quartz sands at Hooker and the Gething/Rock Creek sands at Niton and Caroline in central Alberta.

SOUTHERN ALBERTA: HOOKER

Discovered by Compton in 1999, the Basal Quartz sandstone pool at Hooker is the southern Alberta extension of the Lower Cretaceous Deep Basin gas trend. Current production extends over five townships, and in 2007, we drilled 10 wells at Hooker.

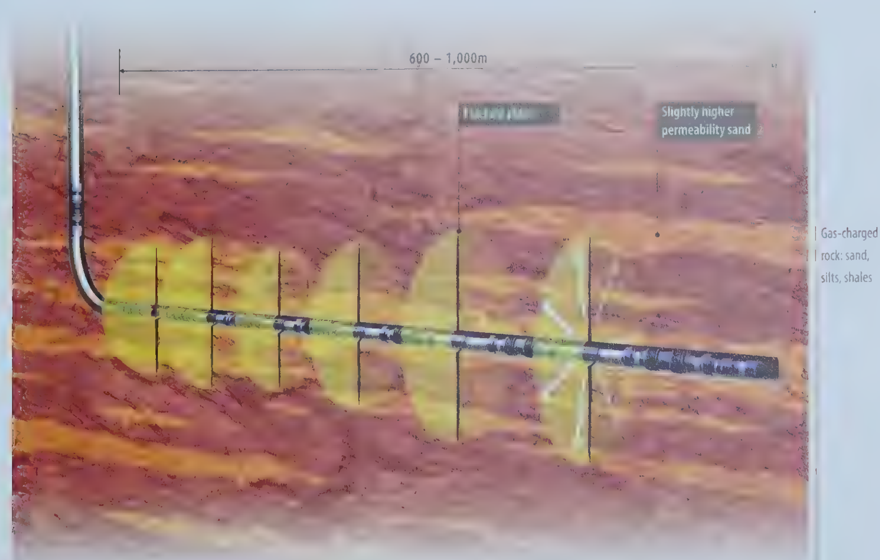
In March 2008, Compton successfully completed the first horizontal well in southern Alberta at Niton targeting the Basal Quartz formation utilizing multi-stage fracturing technology. The well at 9-17-17-29W4 was drilled with a 700 metre horizontal leg that flow tested at six mmcf/d. It is scheduled to be tied-in during mid March. A second horizontal well is currently drilling at 15-30-16-29W4 and 15 follow-up locations have been identified.

While Compton has been employing horizontal drilling and multi-stage frac technology in the Niton area in central Alberta with good success, the 9-17 well at Hooker is of major significance in that it establishes that this technology is applicable to the development of the Hooker Basal Quartz play in southern Alberta. To date the Hooker play has been developed through drilling one to two vertical wells per section. Reservoir modeling indicates up to four vertical wells per section may be necessary to fully develop the play. A horizontal well could replace two to three vertical wells, eliminating the need for extensive down-spacing in the area.

Compton's Callum Cowley Foothills Gas Plant

> "The application of horizontal multi-stage fracing technology throughout all of our natural gas resource plays should have a dramatic impact on Compton's production, cash flow, and value."

Schematic of a typical Horizontal Well
Showing a multi-stage fracture process. This will access more gas-charged rock and increase productivity



Review of Operations

CENTRAL ALBERTA: NITON AND CAROLINE

The Niton area in central Alberta, 150 miles west of Edmonton, is in the Alberta Deep Basin fairway. Our main targets are the Jurassic Rock Creek and Cretaceous Gething, analogous to the Hooker pool in southern Alberta. Proprietary exploration, development, and operational knowledge gained in southern Alberta has resulted in accelerated growth of this core area. In 2007, we drilled 35 wells at Niton and Caroline.

We experienced significant drilling success with our Rock Creek horizontal gas well program at Niton in 2007. The average cost to drill and complete a Niton horizontal gas well is $4.5 million, or roughly twice the cost of a comparative vertical Rock Creek gas well. With a 30 day initial production average of 5.0 mmcfe/d per well, horizontal wells produce about four times that of a comparative vertical well. Compton's average horizontal gas well is 2,600 meters deep and has a 1,000 meter open-hole section. Multiple open-hole packers are set within the horizontal section and three to four staged hydraulic fractures are completed. At year end, we had eight Niton horizontal Rock Creek wells on production. Six of these wells were gas wells and two were oil wells, with the gas wells producing approximately 16.2 mmcfe/d in aggregate and the two oil wells were producing a combined 153 boe/d.

Central Alberta – Niton

To date in 2008 we have drilled two additional horizontal wells at Niton and a third well is currently drilling. The first well tested 3.0 mmcf/d and most recently, the well at 4-27-52-17W5 completed at the end of February is currently flow testing at 11 mmcf/d. The third well is scheduled to be completed later this month. Production from these wells will be facility constrained pending the completion of additional compression and gathering lines. This work is currently underway and is scheduled for completion by the end of March barring any delay resulting from an early spring break-up. A total of 10 additional locations are planned for this area in 2008.

In 2008, Compton's Niton budget plans for 15 horizontal wells using this multi-stage frac technology. Last year's focus by a number of producers, including Compton, targeted the Compton discovered Edson Rock Creek P pool. Following the Niton Rock Creek successes, Compton posted and acquired 100% interest in 12 sections of mineral rights on a second Rock Creek discovery. Late in 2007, Compton drilled Edson 00/01-31-052-16W5M/0 discovery well on this 100% block of land. This well was successful and is currently producing at 3.5 mmcfe/d.

All major compression equipment has been ordered for this play and we are currently drilling the third and fourth horizontal wells in this play. Pending break-up and drilling success, we plan to have eight 100% working interest horizontal wells on stream by the end of May 2008.

For 2008 we have allocated approximately $135 million or 33% of our total planned capital expenditures to our central Alberta resource play. We plan to drill 48 wells in this area, with 13 of these wells slated to be horizontal. The 2008 plan is to continue to aggressively drill similar Rock Creek plays and to transfer this multi-staged horizontal fracture technology to other Compton operated deep basin gas plays throughout Alberta.

FOOTHILLS

Our Callum/Cowley property consists of a series of over pressured, thrusted, low permeability Belly River sands in the foothills of southern Alberta. A total of 15 exploratory wells have been drilled over the life of the play. Based on our initial detailed geological, geophysical, and engineering analysis of seismic, cores, well logs, and test and production data, Callum appears to exhibit many similarities to the deep unconventional gas pools of the Rocky Mountain region of the United States.

In 2007, we drilled a horizontal well targeting a specific group of sands plus intersecting mapped fracture systems. The well came on production at approximately 6.5 mmcf/d, without stimulation. Further reservoir and completion work is planned on this well bore in 2008.

Compton Callum Foothills Gas Plant

During the fourth quarter of 2007, we acquired WIN Energy Inc., a junior oil and gas company that was active on lands immediately adjacent to ours. This $30 million acquisition added 68,000 gross (53,600 net) acres of undeveloped land in the Cowley area in southern Alberta prospective for the thrusted Belly River trend. As at December 31, 2007, we held approximately 239 net sections of high impact exploration lands at Callum and Cowley.

With our acquisition of WIN Energy Inc., we also acquired 55 kilometres of 2D seismic and a new 36 square mile 3D seismic survey surrounding currently producing wells. Using this seismic data, we plan to replicate our recent horizontal well success at Callum in the Cowley area. In 2008, we plan to drill four extended reach horizontal wells. These wells will be oriented to intersect the maximum number of natural fractures in the foothills gas play. Each of these horizontal wells will use multi-stage fracturing techniques and they will be drilled from existing pads to minimize our environmental impact. We plan to drill a total of nine wells in the Callum and Cowley area in 2008.

"The acquisition of WIN Energy Inc. added 68,000 gross acres of undeveloped land in the Cowley area of southern Alberta."

Compton treats the southern Alberta Foothills region as a unique environmental eco-system. In conjunction with a number of southern Alberta ranching operations, we are completing a rangeland health assessment that addresses optimal ways to restore these systems to their natural state. This includes funding of studies on native rough fescue grasses by the University of Alberta, as well as working closely with both industry and landowner work groups. Surface impact on all proposed wells will be minimized by using existing drill pads or by selecting surface areas on sites previously disturbed by the agriculture industry.

Review of Operations

Operating Results

UNDEVELOPED LAND

In 2007, we continued to build and maintain a dominant land position in our core areas. The Company's total net land inventory increased 15% in 2007, with acquisitions occurring primarily in the southern and central Alberta core areas. Net undeveloped land increased 12% from the prior year.

LAND SUMMARY

Area	Undeveloped Acres Gross	Undeveloped Acres Net	Total Acres Gross	Total Acres Net
Southern Alberta	576,253	537,631	1,058,145	941,972
Central Alberta	311,835	225,437	692,453	399,042
Peace River Arch	60,660	35,969	128,980	67,195
Northern Alberta	143,840	87,345	226,210	122,876
Other	28,542	7,080	63,149	11,750
December 31, 2007 total	**1,121,130**	**893,462**	**2,168,937**	**1,542,835**
December 31, 2006 total	980,179	798,192	1,838,863	1,339,481

During 2008, we plan to continue to invest in the future and expand in our core areas. Our 2008 budget includes $28 million directed towards land acquisitions and seismic surveys in our major operating areas.

DRILLING ACTIVITY

We drilled 322 gross (266 net) wells in 2007 with a 97% success rate, compared with 342 gross (274 net) wells in 2006.

Of the 322 wells drilled in 2007, 91% were classified as development wells and nine percent were classified as exploratory wells, compared to 84% and 16% respectively in 2006. The higher percentage of development wells in the current year reflects the increasing maturity of our oil and gas plays.

DRILLING SUMMARY

Years ended December 31,	Natural Gas	Oil	D&A	Total	Net	Success
Southern Alberta	236	–	1	237	208	100%
Central Alberta	37	8	6	51	36	88%
Peace River Arch	3	17	3	23	13	87%
Standing, cased wells				11	9	
2007 Total				**322**	**266**	**97%**
2006 Total	266	56	20	342	274	

RESERVES

Netherland, Sewell & Associates Inc. ("NSAI"), independent reserve evaluators, have completed an evaluation of 96% of Compton's petroleum and natural gas reserves in accordance with National Instrument 51-101. The remaining four percent of the Company's reserves have been evaluated internally.

As required by National Instrument 51-101 *"Standards of Disclosure for Oil and Gas Activities"* ("NI 51-101"), Compton filed Form 51-101 F1 as part of its Annual Information Form ("AIF"). The AIF is considered comprehensive. Certain information has been summarized below regarding the Company's operations. All such information is consistent with the Form NI 51-101 F1 filing. Compton's extended disclosure contained in the AIF is available on both the SEDAR website and Compton's website.

SUMMARY OF ESTIMATED RESERVE VOLUMES – FORECAST PRICES AND COSTS [(1)]

	Crude Oil		Natural Gas		NGLs		Sulphur		Total	
As at December 31, 2007	Gross (Mbbl)	Net (Mbbl)	Gross (Bcf)	Net (Bcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mlt)	Net (Mlt)	Gross (Mboe)	Net (Mboe)
Proved										
Developed producing	9,015	8,501	502	411	9,182	6,498	1,968	1,674	103,884	85,205
Developed non-producing	222	197	55	45	1,079	749	66	55	10,464	8,559
Undeveloped	1,695	1,502	188	154	2,100	1,432	149	124	35,216	28,710
Total proved	10,933	10,199	745	610	12,362	8,679	2,183	1,853	149,564	122,474
Probable	6,495	5,842	625	510	9,820	6,879	839	711	121,255	98,391
Total proved plus probable	**17,427**	**16,042**	**1,369**	**1,120**	**22,182**	**15,558**	**3,022**	**2,563**	**270,819**	**220,865**
2006 total proved plus probable	29,233	26,213	1,189	984	19,068	13,761	2,271	1,975	248,755	205,895

(1) Numbers may not add due to rounding.

In 2007, we added 22 MMboe, after production, to our proved plus probable reserves primarily through the drill bit. Total proved plus probable reserves increased nine percent from the prior year to 271 MMboe. Year end 2007 reserves do not include any reserves associated with our light oil asset at Worsley, which was sold at the end of the third quarter of 2007.

Our total proved reserve base is comprised of 84% natural gas and 16% liquids. Proved producing reserves comprise 69% of total proved reserves, while total proved reserves account for 55% of the proved plus probable reserves. We have a 13 year proved and a 23 year proved plus probable reserve life index.

NET PRESENT VALUE OF RESERVES – FORECAST PRICES AND COSTS [(1)]

	Future net revenue before income taxes [(1)] discounted at a rate of		
($millions)	0%	8%	10%
Proved			
Producing	$ 2,872	$ 1,453	$ 1,304
Non-producing	383	183	160
Undeveloped	1,020	416	345
Total proved	$ 4,275	$ 2,051	$ 1,809
Probable	3,800	1,356	1,109
2007 Total proved plus probable	**$ 8,075**	**$ 3,406**	**$ 2,919**
2006 proved plus probable	$ 7,633	$ 3,312	$ 2,845

(1) Pricing assumptions are the average of four major Canadian oil and gas evaluation firms. Numbers may not add due to rounding.

Review of Operations

Future net revenues are calculated based upon estimated revenue less royalties, operating costs, future development costs, and well abandonment costs. Estimated income taxes have not been deducted. The net present value should not be considered the current market value of our reserves or the costs that would be incurred to obtain equivalent reserves.

RESERVE RECONCILIATION (BEFORE ROYALTIES) – FORECAST PRICES AND COSTS [1]

	Crude oil, Ngls, & Sulphur		Natural Gas		Total		
	Proved (Mbbl)	Probable (Mbbl)	Proved (Bcf)	Probable (Bcf)	Proved (Mboe)	Probable (Mboe)	Proved plus Probable (Mboe)
December 31, 2006	32,745	17,827	687	502	147,218	101,537	248,755
Extensions, improved recovery, & discoveries	1,460	1,770	60	113	11,511	20,549	32,059
Technical Revisions	2,254	(3,377)	14	(39)	4,627	(9,848)	(5,221)
Acquisitions	1,386	948	49	50	9,583	9,269	18,851
Dispositions	(9,753)	(14)	(13)	(1)	(11,940)	(252)	(12,192)
Production	(2,616)	–	(53)	–	(11,434)	–	(11,434)
December 31, 2007	25,477	17,154	745	625	149,564	121,255	270,819

(1) Numbers may not add due to rounding.

FINDING & DEVELOPMENT COSTS

FD&A costs *($/boe)*	**2007**	2006	2005	3 Year Average
Including future capital				
Proved	$ **23.36**	$ 18.48	$ 15.42	$ 17.85
Proved plus probable	$ **12.86**	$ 13.57	$ 13.02	$ 13.17
Excluding future capital				
Proved	$ **24.18**	$ 14.38	$ 12.84	$ 15.22
Proved plus probable	$ **9.95**	$ 8.85	$ 7.05	$ 8.27

Compton's deep gas operations

Our People

"Across disciplines and through knowledge sharing and a collaborative environment, Compton encourages and enables its employees to be the best they can be for the benefit of all shareholders."

"Our dedicated and hard working employees form the foundation of Compton's future."

Our Management

William Cover,
Manager, Drilling & Completions

Robert Dion,
Manager, Finance

Gary Follensbee,
VP Engineering Exploitation

George Fukushima,
Manager, Reserves

Richard Joy,
Manager, Exploration Central

Marc Junghans,
VP Exploration

John Kendrick,
Manager, Environment, Health & Safety

Lorna Klose,
Manager, Investor Relations

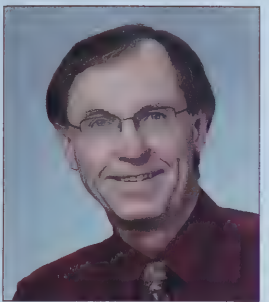
Norm Knecht,
VP Finance & C.F.O.

Theresa Kosek,
Accounting Manager

Bill Leonard,
Manager, Human Resources

Bill McCloskey,
Manager, Exploration South

“Compton’s management team improves processes, encourages innovation and creativity, and ensures that outstanding efforts are recognized and appreciated.”



Garry McCullough,
Land Manager

Tim Millar,
VP, General Counsel & Corporate Secretary

Shelley Milne,
Accounting Manager, Joint Operations

Duane Monea,
Manager, Government Relations

Wade Mrochuk,
Production Manager

Brian Nowak,
Manager, Production Accounting

Larry Osaka,
Manager, Southern Alberta Shallow Gas

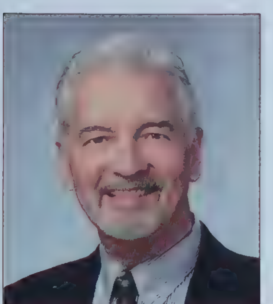
Paul Parzen,
Manager, IT, Risk & Internal Audit

Murray Stodalka,
VP Operations & Engineering

Rob Symonds,
VP Foothills & Corporate Development

Pary Weiler,
Manager, Surface Land

Darcy Weston,
Manager, Analytics and Special Projects



Bob Wilson,
Manager, Engineering North

"Through the efforts of our managers and their teams, Compton has developed ready responses to the opportunities and challenges presented daily in its business."

Responsible Corporate Citizenship

"We are conscious of our social investment responsibilities. The impact of our work on the communities in which we operate matters to Compton."

Corporate Citizenship

Compton recognizes the importance of and positive impact that results from responsible corporate citizenship. We are committed to behaving ethically and contributing to economic development while improving the quality of life for our employees, their families, and the local community. We believe in giving back to the communities in which we operate and, to this end, we have supported numerous local initiatives throughout 2007.

EDUCATIONAL PARTNERSHIPS

For the past seven years, Compton has formed a Corporate/Educational Partnership with a Calgary Board of Education Public School. During the 2006-2007 school year Compton partnered with two schools: Buchanan Elementary School in Calgary and École Joe Clark Elementary School in High River. Each partnership supported a variety of initiatives as identified by the staff, parents, and students of each school. Judith Edge, Principal of Buchanan Elementary said, "Your donation is making a tremendous difference to our students and staff." We also supported our Calgary partner school with Compton's Student Ambassador Program, which sponsored three university students to work with the students and staff at Buchanan during May and June of 2007.

Compton has formed two Educational Partnerships for the 2007-2008 school year. These partnerships will once again focus on enabling and assisting the staff at each school as they work to enhance the quality of educational opportunities and experiences for the students at Chief Justice Milvain Elementary School in Calgary and Prairieview Elementary School in Vulcan, Alberta.

Grow With Us
Canada
Proud 4-H Supporter

Calgary Board of Education

Claresholm & District Health Foundation

Special Olympics Foothills
WINNING AT LIFE

STARS

Rotary International

COMMUNITY PARTICIPATION

Compton's Corporate Sponsorship and Donation Programs contribute to charities and community endeavors that enhance the quality of life in the areas where we are active. Since 2005 Compton has sponsored YMCA Calgary Leaders in Training Program. This leadership development program has given hundreds of junior high school aged students the opportunity to develop their leadership skills.

Compton supported the United Way and S.T.A.R.S during 2007 and, as well, we made contributions to well over one hundred not-for-profit organizations, athletic teams, schools, and community-based organizations in areas such as High River, Okotoks, Calgary, Drayton Valley, Grande Prairie, Vulcan, and Nanton, to name only a few. Compton is committed to assisting in the enhancement of the communities in which we operate.

Photo: Cowgirl Creations

Responsible Corporate Citizenship

Environment, Health and Safety

The Human Resources, Compensation, Environmental, Health and Safety Committee of the Board of Directors undertakes, with Management, all of the necessary procedures, policies, and industry practices designed to protect our employees and contractors, as well as members of the public and the environment. We are committed to responsible resource development. Operations at both the corporate and field levels are routinely assessed in an effort to identify opportunities to enhance environmental, health and safety ("EH&S") performance. By meeting or surpassing all applicable regulatory requirements, education, and training of personnel on EH&S polices and procedures, and following industry best practices, we believe our operations are safer for employees, community residents, and stakeholders, in addition to providing minimal environmental impact.

ENVIRONMENT

Environmental protection is paramount to both the success and reputation of the Company, and, as such, we strive to minimize our environmental footprint in all areas of operation, both initially and throughout the life of the operations of the well or facility. Operating in a manner that is environmentally responsible and the long term protection of environmental quality are important values that the Company demonstrates through:

- Site inspections and assessments to ensure compliance with environmental regulatory legislation and standards;
- Implementation of internal, strategic management programs;
- Networking with regulators and peer associations to improve existing legislation and share best practices;
- Participation in industry programs that benchmark and measure our performance with that of our industry peers;
- Evaluation of the environmental impact of all new projects;
- Effective project planning and implementation, reduction of emissions, waste minimization, and energy conservation.

HEALTH & SAFETY

Heath and safety management is a fundamental value of the executive leadership team, management, and employees of Compton. In addition to being an industry leader in health and safety practices, we are committed to carrying out our operations in a safe and responsible manner. Employees, contractors, and subcontractors are required to be familiar with and adhere to Compton's safety policies and procedures, regulatory legislation, industry guidelines, and best practices. We continue to be below industry average in employee total recordable injury ratio, contractor lost time ratio, and contractor total recordable injury ratio. Compton has not experienced an employee lost time accident since January 2001.

In 2007 Compton received the *"Work Safe Alberta 2006 Best Safety Performer Award"* jointly issued by Alberta Employment, Immigration and Industry and the Occupational Health and Safety Council. This distinction was granted to the top 300 of 140,000 Alberta employers for exceptional performance in workplace health and safety, affirming Compton's exceptional safety standards.

To demonstrate a commitment to the continuous improvement of our health and safety practices, the Company undertakes initiatives such as:

- Hazards assessments of our work sites and operations;
- Annual safety audits to ensure our facilities meet or exceed regulatory standards;
- Management systems in place which measure and review EHS objectives and targets set in industry recognized categories, such as lost time accidents, days away from work, and total recordable injuries;
- Quarterly reporting of our Health, Safety and Environmental practices to Compton's Human Resources, Compensation, Environmental, Health and Safety Committee of the Board of Directors, and such reporting is certified by the President and the Vice President of Operations & Engineering;
- Effective emergency response plan development, in addition to conducting routine training and testing;
- Maintaining an industry recognized safety program;
- Participation in the *"Safety Stand Down"* program providing an opportunity for members of the Board of Directors, Executive, employees, and contractors to meet at the field level to discuss safety and environmental issues; and
- Diligent tracking and investigation on all safety and environmental incidents and near misses.

J. S. Allan

M.F. Belich

I.J. Koop

J.W. Preston

J.T. Smith

J.A. Thomson

E.G. Sapieha

"Compton's Board is collectively responsible for ensuring that the Company is held to the highest standards of financial and operating performance. The development and implementation of policies and strategies are delegated to Compton's chief executive and its executive officers."

Accountability

Corporate Governance

Compton's Board of Directors believes adopting and upholding the highest standards of corporate governance is critical for building stakeholder confidence and for the overall success of the Company. Sound corporate governance ensures transparency and accountability for our objectives, strategy, controls, and overall performance. The Corporate Governance Committee and Board of Directors continuously monitor applicable legislation and respond appropriately to ensure the Company's compliance.

We continually adjust our practices to reflect the requirements of the New York Stock Exchange ("NYSE") Listing Standards, the Sarbanes-Oxley Act of 2002, and other current governance issues.

CANADIAN CORPORATE GOVERNANCE REQUIREMENTS

The Canadian Securities Administrators approved National Policy 58-201, *"Corporate Governance Guidelines"* (the "Best Practices Policy") and National Instrument 58-101, *"Disclosure of Corporate Governance Practices"* (the "Disclosure Instrument,") in 2005. The Best Practices Policy provides guidance on corporate governance practices, following U.S. initiatives under the Sarbanes-Oxley Act and newly adopted corporate governance rules of the NYSE and NASDAQ. The Disclosure Instrument specifically requires issuers to make certain corporate governance related disclosures. The disclosures required under the Disclosure Instrument generally correspond to the guidance in the Best Practices Policy.

A description of our corporate governance disclosures, as required by the Disclosure Instrument, is set forth in our Management Proxy Circular, which may be found on our website at www.comptonpetroleum.com.

U.S. CORPORATE GOVERNANCE REQUIREMENTS

Compton's common shares commenced trading on the NYSE on December 6, 2005. The Company is classified as a foreign private issuer in the United States by the Securities Exchange Act of 1934 (the "Exchange Act") and is therefore permitted to follow Canadian corporate governance regulations, except for:

- audit committee member independence requirements under Rule 10A-3 of the Exchange Act;
- the requirement to disclose any significant differences between the Company's corporate governance practices and those followed by domestic companies under the NYSE listing standards; and
- the requirement for the Company to submit an Annual Written Affirmation to the NYSE, confirming the Company's compliance with the audit committee independence requirements of Rule 10A-3 and that the Company has provided a statement of significant corporate governance differences, and to notify in writing the NYSE if any Officer becomes aware of a material non-compliance.

Our audit committee members are independent under Rule 10A-3 of the Exchange Act. Our corporate governance practices do not differ significantly from those followed by domestic U.S. companies under NYSE listing standards, with the exceptions that (i) we do not have an internal audit function and (ii) the CEO's compensation is finally approved by the Board of Directors on the recommendation of the Human Resources, Compensation, Environmental, Health and Safety Committee. We have filed our Annual Written Affirmation with the NYSE.

BOARD OF DIRECTORS AND BOARD COMMITTEES

BOARD MANDATE AND COMPOSITION

The Board of Directors (the "Board") has explicitly assumed responsibility for the stewardship of the Company. The Board shall operate by delegating certain of its authorities to Management, including the day to day conduct of the business of the Company and overseeing the activities of Management, while reserving certain powers for itself. The Board's fundamental objectives are to enhance and preserve long term shareholder value, to provide stewardship in order that the Company meets its obligations on an ongoing basis, and to operate in a reliable and safe manner.

The written Charter of the Board explicitly acknowledges responsibility for the stewardship of the Company and requires the Board to determine that:

- the Company has established long term goals and a strategic planning process;
- the principal risks of the Company's business are identified and appropriate systems are implemented to manage those risks;
- there is sufficient succession planning including appointing, training, managing, and monitoring Management;

- the Company has a communications policy;
- the Company's internal controls and management information systems have sufficient integrity; and
- the Company's approach to governance issues and the implementation of principles for the management of corporate governance fosters a culture of integrity throughout the Company.

Based upon applicable Canadian and U.S. securities laws and the NYSE corporate governance rules, we have adopted *"Standards of Independence,"* which may be viewed in full on our website. The Board must affirmatively determine on an annual basis, whether or not its members are independent. Six out of seven Directors, including the Chairman of the Board, have been determined to be independent. Mr. Sapieha is a non-independent Director because of his position as President & CEO of the Company.

A full copy of the Charter for the Board of Directors can be found on our website at www.comptonpetroleum.com.

COMMITTEES OF THE BOARD

Subject to applicable law, the Board may delegate its powers, duties, and responsibilities to Committees of the Board. In this regard, the Board has established four standing Committees, the (i) Human Resources, Compensation, Environmental, Health and Safety Committee; (ii) Audit, Finance and Risk Committee; (iii) Engineering, Reserves and Operations Committee; and (iv) Corporate Governance Committee. The mandate of each committee is reviewed annually and is summarized below. All Committees are composed exclusively of independent Directors.

Human Resources, Compensation, Environmental, Health and Safety Committee

Chairman: Irvine Koop
Members: Mel Belich, John Preston, Jeff Smith, John Thomson, Steve Allan

The Committee's mandate is to assist the Board in fulfilling its oversight responsibilities with respect to human resources and compensation. Additionally, the Committee monitors the environmental, health, and safety practices and procedures of the Company for compliance with applicable legislation, conformity with industry standards, and prevention or mitigation of loss.

The Committee also has the responsibility to:

- review and oversee human resources policies of the Company;
- review succession plans for key Management positions within the Company;
- develop performance objectives for the CEO and other Officers and assess their performance against such objectives;
- recommend to the Board, salary and other remuneration for Officers of the Company. The Committee also monitors performance objectives for Officers in order that they are aligned with shareholders' interests and corporate goals;
- recommend to the Board in respect of all other compensation matters, including long and short term incentives such as bonuses, stock option plans, and other benefits;
- review and recommend compensation for Board and Committee service.

The Committee fulfills its environmental, health, and safety responsibilities by:

- overseeing the Company's policies and guidelines with respect to environmental, health, and safety matters regarding the Company's facilities and operations;
- undertaking with management those policies, guidelines, practices, and procedures designed to manage risk and assume compliance with all workplace, environmental, health, and safety laws;
- reviewing and monitoring the Company's policies, procedures, and practices relating to the documentation and reporting of environmental, health, and safety regulatory approvals, compliance, and incidents; and
- generally, reviewing the Company's performance related to environment, health, and safety and confirming with management that long range preventative programs are in place.

The full Human Resources, Compensation, Environmental, Health and Safety Committee Charter may be found on Compton's website at www.comptonpetroleum.com.

Accountability

Audit, Finance and Risk Committee

Chairman: John Thomson

Members: Mel Belich, Irvine Koop, John Preston, Jeff Smith, Steve Allan

The Audit, Finance and Risk Committee is mandated to oversee that Management is responsible for creating and maintaining an effective risk management and internal control framework. This framework provides reasonable assurance that the financial, operational, and regulatory objectives of the Company are achieved and that the statutory responsibilities of the Board are discharged.

The Committee fulfills its role on behalf of the Board by overseeing:

- the review, disclosure, and integrity of the Company's financial statements, Management's Discussion and Analysis of financial conditions and results of operations, and other financial information;
- the external auditor's qualifications, independence, and performance;
- the Company's compliance with legal and regulatory requirements;
- risk management, management information systems, governmental legislation, and external business of the Company;
- the effectiveness and integrity of the Company's system of disclosure controls and internal controls; and
- reviewing the appointments of the Chief Financial Officer and other key financial executives.

The Committee oversees the operation of an anonymous and confidential toll free telephone number and website for employees, contractors, and others to call with respect to accounting irregularities or ethical violations. The Committee has also established a procedure for the receipt, retention, treatment, and regular review of any such reported activities. This telephone number is 1-800-661-9675 and the confidential website address is www.compton-eweb.com.

The full Audit, Finance and Risk Committee Charter may be found on Compton's website at www.comptonpetroleum.com.

Engineering, Reserves and Operations Committee

Chairman: Jeff Smith

Members: Mel Belich, Irvine Koop, John Preston, John Thomson, Steve Allan

The Committee's mandate is to review and make recommendations to the Board on the Company's engineering and reserves policies.

The Committee fulfills its oversight role on behalf of the Board and is responsible for:

- the Company's overall policies and guidelines with respect to engineering, reserves, and operations;
- undertaking with Management all necessary procedures and policies to comply with regulations and guidelines applicable to the Company and enunciated by the applicable regulatory authorities including providing assistance to Management in compliance with National Instrument 51-101, preparation of the Statement of Reserves (Form 51-101 F1), Evaluator's Report (Form 51-101 F2), and Management Report (Form NI 51-101 F3);
- meeting with the Company's Vice President of Operations & Engineering, other senior reserves personnel, and the independent reserves evaluator to review and consider the Company's reserves; and
- reviewing, assisting, and making recommendations to the Board in respect of the annual appointment of the Company's independent qualified reserves evaluators.

The full Engineering, Reserves and Operations Committee Charter may be found on Compton's website at www.comptonpetroleum.com.

Corporate Governance Committee

Chairman: Mel Belich

Members: Irvine Koop, John Preston, Jeff Smith, John Thomson, Steve Allan

The Corporate Governance Committee is responsible for developing the Company's approach to governance issues and to assist the Board in fulfilling its oversight responsibilities with respect to the development and implementation of corporate governance. The Committee functions with a view to fostering a culture of integrity within the Company.

The Committee fulfills its oversight role on behalf of the Board and is responsible to:

- recommend initiatives to maintain high standards of corporate governance;
- assess the effectiveness and performance of the Board as a whole, the Chairman of the Board, Board Committees, Committee Chairs, and individual Directors;
- define and monitor the relationship, roles, and authority of the Board and Management;
- review and evaluate corporate communication policies and practices; and
- monitor compliance with the Code of Business Conduct and Ethics.

The Committee also has the responsibility to:

- identify nominees for the Board and its Committees;
- evaluate the competencies and skills necessary for the Board as a whole to possess, the competencies and skills that existing Directors possess, and the competencies and skills each new nominee will bring to the Board;
- propose nominees for re-election as Directors by the shareholders at the annual meeting; and
- propose candidates for appointment to senior Management, Executive, and Officer positions.

The full Corporate Governance Committee Charter may be found on Compton's website at www.comptonpetroleum.com.

Special Committee of the Independent Members of the Board

Chairman: **Mel Belich**

Members: **Irvine Koop, John Preston, Jeff Smith, John Thomson, Steve Allan, Peter Seldin**

The Committee is responsible for conducting a formal review of the Company's business plans and strategic alternatives for enhancing shareholder value. Such review will include, among other things, exploring potential asset divestments, equity alternatives, strategic alliances, joint venture opportunities, mergers, or a corporate transaction.

The Committee will also have the responsibility (i) to retain and oversee independent financial advisors to assist the Committee in the conduct of its review, (ii) to make reports and recommendations to the Board in respect of the review, and (iii) generally to define and monitor the relationships and roles of the Committee, Management, and advisors in respect of the review.

CODE OF BUSINESS CONDUCT AND ETHICS

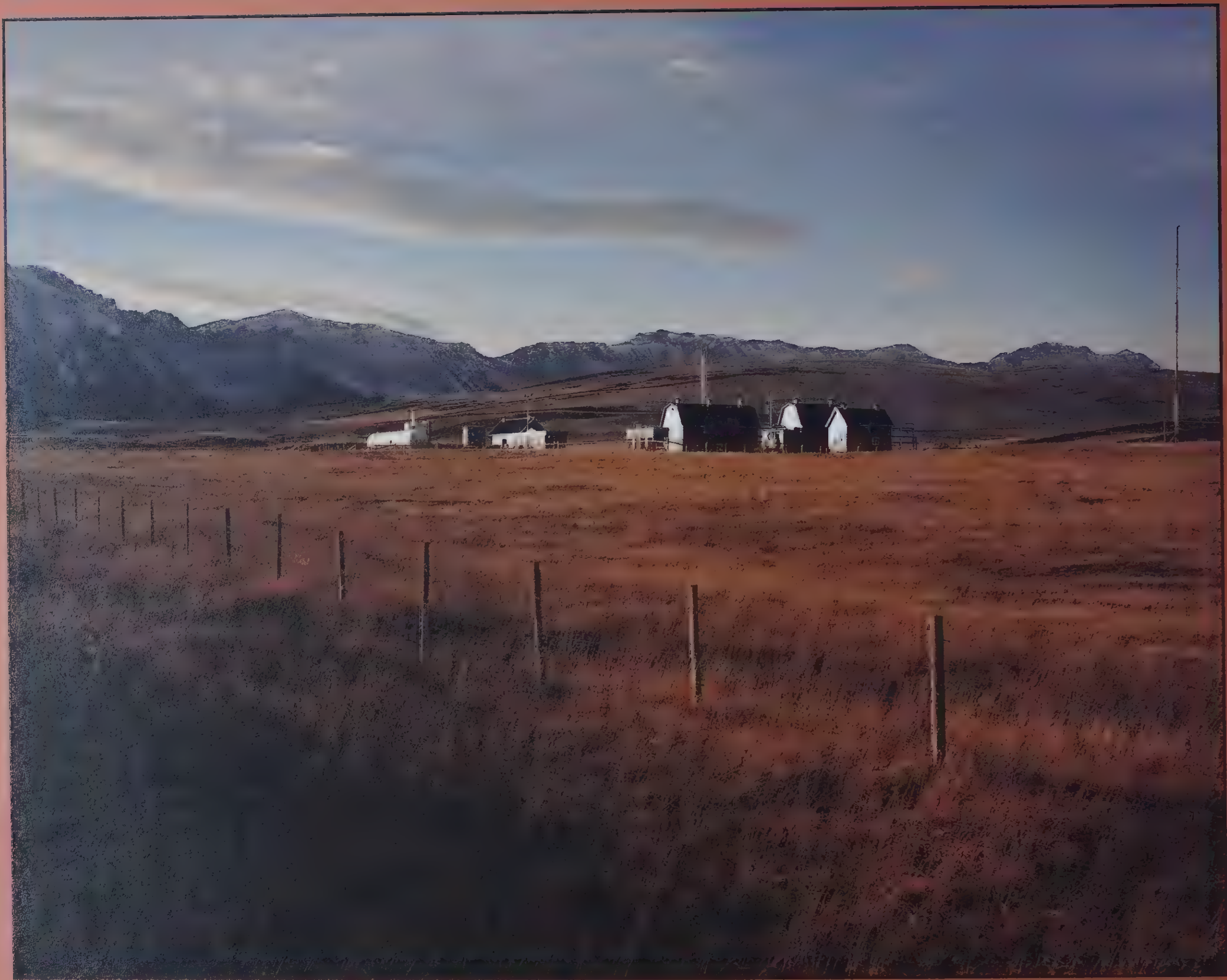
Compton's Code of Business Conduct and Ethics (the "Code") holds our Directors, Officers, employees, and consultants to high standards of legal and moral conduct in all areas of operations. In addition to meeting legal and regulatory requirements, we strive to conduct all operations fairly and with integrity.

The Board encourages and promotes a culture of ethical business conduct through its guidance provided to Officers and senior members of Management and its oversight of the daily operations of the Company. Additionally, the Whistle Blower Policy (the "Policy") adopted by the Company promotes a culture of openness, honestly, and accountability. The Policy establishes procedures for the receipt, retention, treatment, and regular review of any unlawful activities, accounting irregularities or ethical violations.

The Board monitors compliance with the Code through the use of an Ethics Hotline, which is an anonymous and confidential toll free telephone number. Additionally, any violations of the Code brought to the attention of Management are reported to the Board. No waivers from the Code were granted to the Company's Directors, Officers, employees, or consultants in 2007.

Compton's Code of Business Conduct and Ethics and Whistle Blower Policy may be viewed on our website at www.comptonpetroleum.com.

Management's Discussion & Analysis



Compton's Lowley Foothills Gas Plant

Advisories

Management's Discussion and Analysis ("MD&A") is intended to provide both an historical and prospective view of our activities. The MD&A was prepared as at March 24, 2008, and should be read in conjunction with the audited consolidated financial statements and related notes for the year ended December 31, 2007 and the advisories set out below. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). A reconciliation to U.S. GAAP is included in Note 21 to the consolidated financial statements.

FORWARD LOOKING STATEMENTS

Certain information regarding the Company contained herein constitutes forward-looking information and statements and financial outlooks (collectively, "forward-looking statements") under the meaning of applicable securities laws, including Canadian Securities Administrators' National Instrument 51-102 Continuous Disclosure Obligations and the United States Private Securities Litigation Reform Act of 1995. Forward-looking statements include estimates, plans, expectations, opinions, forecasts, projections, guidance, or other statements that are not statements of fact, including statements regarding (i) cash flow and capital and operating expenditures, (ii) exploration, drilling, completion, and production matters, (iii) results of operations, (iv) financial position, and (v) other risks and uncertainties described from time to time in the reports and filings made by Compton with securities regulatory authorities. Although Compton believes that the assumptions underlying, and expectations reflected in, such forward-looking statements are reasonable, it can give no assurance that such assumptions and expectations will prove to have been correct. There are many factors that could cause forward-looking statements not to be correct, including risks and uncertainties inherent in the Company's business. These risks include, but are not limited to: crude oil and natural gas price volatility, exchange rate fluctuations, availability of services and supplies, operating hazards, access difficulties and mechanical failures, weather related issues, uncertainties in the estimates of reserves and in projection of future rates of production and timing of development expenditures, general economic conditions, and the actions or inactions of third party operators, and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by Compton. Statements relating to "reserves" and "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and can be profitably produced in the future.

The forward-looking statements contained herein are made as of the date of this MD&A solely for the purpose of generally disclosing Compton's views of its prospective activities. Compton may, as considered necessary in the circumstances, update or revise the forward-looking statements, whether as a result of new information, future events, or otherwise, but Compton does not undertake to update this information at any particular time, except as required by law. Compton cautions readers that the forward-looking statements may not be appropriate for purposes other than their intended purposes and that undue reliance should not be placed on any forward-looking statement. The Company's forward-looking statements are expressly qualified in their entirety by this cautionary statement

NON-GAAP FINANCIAL MEASURES

Included in the MD&A and elsewhere in this report are references to financial measures commonly used in the oil and gas industry, including adjusted cash flow from operations and adjusted net earnings from operations. These financial measures are not defined by Canadian generally accepted accounting principles ("GAAP") and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures provided by other companies. We use these non-GAAP measures to evaluate our performance.

Adjusted cash flow from operations should not be considered an alternative to, or more meaningful than, cash provided by operating, investing and financing activities or net earnings as determined in accordance with Canadian GAAP, as an indicator of our performance or liquidity. Adjusted cash flow from operations is used by us to evaluate operating results and our ability to generate cash to fund future growth through capital investment.

Adjusted net earnings from operations represents net earnings excluding certain items that are largely non-operational in nature and should not be considered an alternative to, or more meaningful than, net earnings as determined in accordance with Canadian GAAP. Adjusted net earnings from operations is used by us to facilitate comparability of earnings between periods.

USE OF BOE EQUIVALENTS

The oil and natural gas industry commonly expresses production volumes and reserves on a barrel of oil equivalent ("boe") basis whereby natural gas volumes are converted at the ratio of six thousand cubic feet to one barrel of oil. The intention is to sum oil and natural gas measurement units into one basis for improved measurement of results and comparisons with other industry participants. We use the 6:1 boe measure which is the approximate energy equivalency of the two commodities at the burner tip. However, boes do not represent a value equivalency at the plant gate where we sell our production volumes and therefore may be a misleading measure if used in isolation.

Management's Discussion & Analysis

Corporate Overview & Strategy

Compton Petroleum Corporation is an independent, public company actively engaged in the exploration for and development and production of natural gas, natural gas liquids, and crude oil in western Canada. Our activities are focused primarily in the Deep Basin fairway in the province of Alberta, in the Western Canada Sedimentary Basin. Our growth and reserve base results predominantly from our exploration and development drilling programs.

Our objective has been and remains that of building an exploration and development company capable of delivering sustainable long term growth. Management has adhered to a consistent strategy in pursuing this objective, including:

- concentrating activities in a limited number of core areas;
- focusing on unconventional long life natural gas reserves in large resource plays;
- pursuing growth through the drill bit, complemented by strategic acquisitions;
- controlling infrastructure and operatorship; and
- maintaining financial flexibility.

Results of Operations

2007 Summary

- Drilled 322 gross (266 net) wells with a 97% success rate.
- Achieved annual average production of 31,326 boe/d.
- Generated adjusted cash flow from operations of $196.2 million, or $1.48 per diluted share.
- Adjusted net earnings from operations for the year were $21.3 million.
- Net earnings for the year were $129.2 million.

Adjusted Cash Flow from Operations and Net Earnings

Years ended December 31,		**2007**	2006	2005
Adjusted cash flow from operations (1) *($000s)*		$ **196,194**	$ 256,305	$ 278,112
Per share:	basic	$ **1.52**	$ 2.01	$ 2.21
	diluted	$ **1.48**	$ 1.92	$ 2.11
Net earnings *($000s)*		$ **129,266**	$ 127,426	$ 81,326
Per share:	basic	$ **1.00**	$ 1.00	$ 0.65
	diluted	$ **0.98**	$ 0.95	$ 0.62

(1) Adjusted cash flow from operations is a non-GAAP term that represents net earnings adjusted for non-cash items. We consider adjusted cash flow from operations to be a key financial measure as it demonstrates our ability to generate the cash flow necessary to fund future growth through capital investment. Adjusted cash flow from operations may not be comparable to similar measures presented by other companies.

Adjusted cash flow from operations

Years ended December 31, ($000s)	***2007***	*2006*	*2005*
Net earnings	*$* ***129,266***	*$ 127,426*	*$ 81,326*
Amortization of deferred charges and other	***3,417***	*1,996*	*2,190*
Tender costs	***–***	*–*	*20,750*
Depletion and depreciation	***151,411***	*143,057*	*105,504*
Accretion of asset retirement obligations	***2,718***	*2,257*	*1,975*
Unrealized foreign exchange (gain)	***(79,740)***	*(665)*	*(7,808)*
Future income taxes	***(26,452)***	*(3,636)*	*52,317*
Unrealized risk management (gain) loss	***5,467***	*(27,522)*	*10,171*
Stock-based compensation	***8,416***	*9,121*	*5,903*
Asset retirement expenditures	***(4,441)***	*(2,352)*	*(749)*
Non-controlling interest	***6,132***	*6,623*	*6,533*
Adjusted cash flow from operations	*$* ***196,194***	*$ 256,305*	*$ 278,112*

Adjusted cash flow from operations declined in 2007 from the prior year's level by approximately $60 million. The major causes of the decline were a $25 million reduction in realized risk management gains, a reduction of $19 million in revenue after royalties, and increases in general and administrative and interest expenses. Additionally, at the end of the third quarter of 2007, we closed the sale of our conventional light oil asset at Worsley, which reduced production, adjusted cash flow from operations, and net income accordingly for the last three months of the year as compared to the prior year.

Net earnings for the year increased by approximately $2 million over 2006 and benefited from a foreign exchange gain of $79 million and a $26 million future income tax recovery.

ADJUSTED NET EARNINGS FROM OPERATIONS

Adjusted net earnings from operations is a non-GAAP measure that represents net earnings adjusted for certain items of a non-operational and non-cash nature. We evaluate our performance on adjusted net earnings from operations which eliminates these non-operational items that can introduce a level of volatility to net earnings determined in accordance with GAAP.

The following reconciliation identifies the after-tax effects of certain items of non-operational nature that are included in our financial results. Adjusted net earnings from operations may not be comparable to similar measures presented by other companies.

SUMMARY OF ADJUSTED NET EARNINGS FROM OPERATIONS(1)

Years ended December 31, ($000s, except per share amounts)	2007	2006	2005
Net earnings, as reported	**$ 129,266**	$ 127,426	$81,326
Non-operational items, after tax			
Unrealized foreign exchange (gain)	**(66,934)**	(550)	(6,339)
Unrealized risk management (gain) loss	**3,711**	(18,027)	6,345
Stock-based compensation	**5,713**	5,974	3,682
Tender costs on repurchase of 9.90% notes	**–**	–	14,414
Future income tax recovery due to income tax rate reductions	**(50,470)**	(49,655)	(5,764)
Adjusted net earnings from operations	**$ 21,286**	$ 65,168	$ 93,664
Per share: basic	**$ 0.17**	$ 0.51	$ 0.75
diluted	**$ 0.16**	$ 0.49	$ 0.71

(1) Adjusted net earnings from operations was referred to as Operating Earnings in prior years.

Management's Discussion & Analysis

REVENUE

Years ended December 31,	**2007**	2006	2005
Average production			
Natural gas *(mmcf/d)*	**145**	142	131
Liquids *(bbls/d)*	**7,166**	9,516	7,646
Total *(boe/d)*	**31,326**	33,187	29,424
Benchmark prices			
NYMEX *(U.S.$/mmbtu)*	**$ 6.86**	$ 7.26	$ 8.55
AECO *($/GJ)*			
Monthly index	**$ 6.27**	$ 6.21	$ 8.04
Daily index	**$ 6.11**	$ 6.19	$ 8.27
WTI *(U.S.$/bbl)*	**$ 72.37**	$ 66.22	$ 56.56
Edmonton par *($/bbl)*	**$ 76.23**	$ 72.77	$ 68.72
Realized prices			
Natural gas *($/mcf)*	**$ 6.33**	$ 6.32	$ 8.36
Liquids *($/bbl)*	**62.28**	59.09	56.47
Total *($/boe)*	**$ 43.82**	$ 44.65	$ 52.54
Revenue *($000s)*			
Natural gas	**$ 334,920**	$ 327,629	$ 398,543
Liquids	**166,067**	213,208	165,698
Total	**$ 500,987**	$ 540,837	$ 564,241

SUMMARY OF REVENUE INCREASES FROM PRODUCTION AND PRICING

($000s)	**Natural Gas Revenue**	**Liquids Revenue**	**Total Revenue**
Reported 2006 revenue	$ 327,629	$ 213,208	$ 540,837
Change in production volumes	7,291	(49,875)	(42,584)
Change in prices	–	2,734	2,734
Reported 2007 revenue	**$ 334,920**	**$ 166,067**	**$ 500,987**

Overall production in 2007 fell 6% from the prior year. Natural gas volumes increased 2%, while liquids production decreased 25% from 2006 volumes. The significant reduction in our year over year liquids volumes is attributable to natural declines and the sale of our conventional light oil asset, Worsley. This transaction closed at the end of the third quarter of 2007.

We market the majority of our natural gas production through a combination of daily and monthly indexed contracts and aggregator contracts. During 2007, approximately 10% of our natural gas production remained committed to longer term aggregator contracts which realized a price that was, on average, $0.75/mcf less than that received on non-aggregator volumes.

Our crude oil sales are priced based upon Edmonton postings and are typically sold on 30 day evergreen arrangements. Natural gas liquids are bid out on an annual basis to obtain the most favourable pricing. We sell our crude oil and natural gas liquids primarily to refineries and marketers of crude oil and natural gas liquids.

Periodically we enter into financial instrument contracts to hedge against price volatility. This activity is fully disclosed in the Risk Management section of this MD&A. Realized commodity prices, as reported in the MD&A, are before any hedging gains or losses.

ROYALTIES

Years ended December 31, ($000s, except where noted)	**2007**	2006	2005
Crown royalties	**$ 86,850**	$ 100,230	$ 105,827
Other royalties	**15,828**	23,447	26,890
Net royalties	**$ 102,678**	$ 123,677	$ 132,717
Percentage of revenues	**20.5%**	22.9%	23.5%

Royalties are paid to various government entities and other land and mineral rights owners. Virtually all Crown royalties are paid to the province of Alberta which has a royalty structure based upon commodity prices and well productivity, with higher prices and well productivity attracting higher royalty rates. Our royalty rate in 2007, as a percentage of revenue, decreased from 2006 as a result of the increased contribution from lower productivity wells to total production.

We anticipate 2008 royalty rates will remain relatively consistent with prior years; however, significant changes to the Alberta royalty structure may occur in 2009 as a result of the recent Alberta royalty review, the final results of which are yet to be announced.

OPERATING EXPENSES

Years ended December 31,	**2007**	2006	2005
Operating expenses *($000s)*	**$ 101,478**	$ 102,643	$ 73,164
Operating expenses per boe *($/boe)*	**$ 8.88**	$ 8.47	$ 6.81

Year over year operating costs remained constant. However, when measured on a $/boe basis, 2007 operating expenses increased by 5% when compared to 2006. Specific increases of note include salaries for field staff and contract operators and rising electricity prices. Additionally, fourth quarter 2007 operating costs included significant lease repair and maintenance costs associated with assets acquired during the last half of the year.

In prior years, operating costs were reported net of third party processing fees. Commencing in 2007, third party processing income is included in revenue and not netted against operating expenses. 2006 and 2005 operating expenses have been reclassified accordingly.

With the current reduced level of activity in the industry, we are now beginning to see indications that cost inflation is moderating. With an increased emphasis on cost controls, we anticipate 2008 operating costs, on a unit of production basis, will remain similar to those experienced in 2007.

TRANSPORTATION EXPENSES

Years ended December 31,	**2007**	2006	2005
Transportation costs *($000s)*	**$ 12,615**	$ 12,564	$ 10,858
Transportation costs per boe *($/boe)*	**$ 1.10**	$ 1.04	$ 1.01

We incur charges for the transportation of our production from the wellhead to the point of sale. Pipeline tariffs and trucking rates for liquids are primarily dependent upon production location and distance from the sales point. Regulated pipelines transport natural gas within Alberta at tolls approved by the government.

2007 transportation expense remained relatively constant with that of 2006. However, with the closing of the sale of our conventional oil property, Worsley, at the end of the third quarter of 2007, our fourth quarter transportation expense fell to $0.55/boe, as our oil trucking requirements were reduced significantly.

Management's Discussion & Analysis

GENERAL AND ADMINISTRATIVE EXPENSES

Years ended December 31, ($000s, except where noted)	**2007**	2006	2005
General and administrative expenses	**$ 41,633**	$ 38,321	$ 34,638
Capitalized general and administrative expenses	**(7,470)**	(9,625)	(11,158)
Operator recoveries	**(2,835)**	(2,465)	(2,257)
Total general and administrative expenses	**$ 31,328**	$ 26,231	$ 21,223
General and administrative per boe *($/boe)*	**$ 2.74**	$ 2.17	$ 1.98

Employee costs associated with increased personnel levels, together with a general increase in remuneration necessary to attract and retain qualified personnel in a very competitive industry, were the main contributors to the increase in general and administrative expenses in 2007. Other increases included insurance and costs associated with ongoing regulatory compliance requirements. Additionally, increased expenses associated with additional office space were incurred as a result of corporate acquisitions. During 2007, we incurred direct expenses totaling approximately $1.5 million relating to compliance requirements pursuant to the U.S. Sarbanes-Oxley Act of 2002 and Canadian Multilateral Instrument 52-109.

General and administrative expenses in 2008 will be impacted by costs associated with current shareholder activism activities. Such costs will include additional legal fees, advisory fees and expenses, and employee retention costs. Such costs are expected to be approximately $22 million, as discussed in the Outlook and Guidance section of this MD&A and Note 20 to the financial statements.

INTEREST AND FINANCE CHARGES

Years ended December 31, ($000s, except where noted)	**2007**	2006	2005
Interest on bank debt, net	**$ 22,476**	$ 14,243	$ 11,520
Interest on Senior Notes	**38,345**	35,880	20,912
Interest expense	**$ 60,821**	$ 50,123	$ 32,432
Finance charges	**2,672**	3,952	2,519
Total interest and finance charges	**$ 63,493**	$ 54,075	$ 34,951
Total interest and finance charges per boe *($/boe)*	**$ 5.55**	$ 4.47	$ 3.25

Weighted average annual debt ($000s, except where noted)	**2007**	2006	2005
Bank debt	**$ 348,216**	$ 254,476	$ 228,381
Effective interest rate	**6.46%**	5.60%	4.23%
Senior notes *(US$)*	**$ 450,000**	$ 412,802	$ 179,583
Effective interest rate	**7.63%**	7.64%	9.50%

Interest expenses relating to bank debt in 2007 increased from the prior year as a result of increased borrowings incurred to fund our 2007 capital program and overall floating interest rate increases.

NETBACKS

Years ended December 31, ($/boe)	2007	2006	2005
Realized price	$ 43.82	$ 44.65	$ 52.54
Realized commodity hedge gain (loss)	1.68	3.24	(0.90)
Royalties	(8.98)	(10.21)	(12.36)
Operating expenses	(8.88)	(8.47)	(6.81)
Transportation	(1.10)	(1.04)	(1.01)
Field operating netback	$ 26.54	$ 28.17	$ 31.46
General and administrative	(2.74)	(2.17)	(1.98)
Interest	(5.55)	(4.47)	(3.25)
Current taxes	–	–	(0.47)
Cash flow netback	$ 18.25	$ 21.53	$ 25.76

RISK MANAGEMENT

Our financial results are impacted by external market risks associated with fluctuations in commodity prices, interest rates, and the Canadian/U.S. dollar exchange rate. We utilize various financial instruments for non-trading purposes to manage and mitigate our exposure to these risks. Our financial instruments are not designated for hedge accounting, and accordingly are recorded at fair value on the consolidated balance sheets, with subsequent changes recognized in consolidated net earnings and other comprehensive income.

Financial instruments utilized to manage risk are subject to periodic settlements throughout the term of the instruments. Such settlements may result in a gain or loss, which is recognized as a realized risk management gain or loss at the time of settlement.

The mark-to-market values of financial instruments outstanding at the end of a reporting period reflect the values of the instruments based upon market conditions existing as of that date. Any change in the fair values of the instruments from that determined at the end of the previous reporting period is recognized as an unrealized risk management gain or loss. Unrealized risk management gains or losses may or may not be realized in subsequent periods depending upon subsequent moves in commodity prices, interest rates, or exchange rates affecting the financial instruments.

Risk management gains and losses recognized in 2007 are outlined below.

Year ended December 31, ($000s)	2007	2006	2005
Commodity contracts			
Realized (gain) loss	$ (19,220)	$ (39,217)	$ 9,663
Unrealized (gain) loss	20,834	(25,775)	5,136
Foreign currency contracts			
Realized (gain) loss	7,739	3,018	(532)
Unrealized (gain) loss	(15,367)	(1,747)	5,035
Total risk management (gain) loss	$ (6,014)	$ (63,721)	$ 19,302
Realized (gain) loss	$ (11,481)	$ (36,199)	$ 9,131
Unrealized (gain) loss	5,467	(27,522)	10,171
Total risk management (gain) loss	$ (6,014)	$ (63,721)	$ 19,302

Management's Discussion & Analysis

DEPLETION AND DEPRECIATION

Years ended December 31,	**2007**	2006	2005
Total depletion and depreciation *($000s)*	$ **151,411**	$ 143,057	$ 105,504
Depletion and depreciation per boe *($/boe)*	$ **13.24**	$ 11.81	$ 9.82

Accelerated capital programs and competition throughout the oil and gas industry during the current and prior years increased the demand and costs of goods and services. This increase in costs is reflected in higher finding, development, and on-stream costs which in turn, have resulted in an increase in depletion and depreciation rates on a boe basis in the current year in comparison to prior periods.

FOREIGN EXCHANGE

The foreign exchange gain recognized on the consolidated statements of earnings results primarily from the translation of our U.S. dollar denominated Senior Notes into Canadian dollars. The Senior Notes are translated and recorded in the financial statements at the year end exchange rate, with any differences from prior measurements being recognized as an unrealized foreign exchange gain or loss.

In 2007, we entered into foreign currency exchange contracts related to our $450 million of U.S. dollar denominated Senior Notes. The notes were issued in 2005 and 2006 and are due in 2013. The strengthening of the Canadian dollar against that of the U.S. resulted in the Company recognizing the unrealized foreign exchange gain referred to in the preceding paragraph. On October 26 and 31, 2007 we entered into foreign exchange forward contracts to purchase U.S.$450 million for C$436 million, as at December 1, 2010 being the second call date on the notes. These contracts effectively crystallized a total foreign exchange gain of approximately $91.7 million.

On November 22, 2005, pursuant to a tender offer, we repurchased U.S.$158 million of the 9.90% Senior Notes issued in 2002. As a result of the repurchase, we crystallized $62 million of the accumulated unrealized foreign exchange gains in 2005 that had previously been recognized with the strengthening of the Canadian dollar subsequent to the note issuance.

STOCK-BASED COMPENSATION

Years ended December 31,	**2007**	2006	2005
Options granted *(000s)*	**2,074**	2,228	2,930
Weighted average fair value of options granted *($/share)*	$ **4.23**	$ 6.90	$ 5.45
Stock-based compensation expense recognized *($000s)*	$ **11,034**	$ 10,488	$ 5,903

We have a stock option plan for employees, officers, and directors. The plan is designed to attract, motivate, and retain outstanding individuals and to align their success with that of our shareholders. The fair value of options granted is estimated on the date of grant using the Black-Scholes option pricing model and the associated compensation expense is recognized over the vesting period.

During 2006, in recognition of the shortage of, and competition for, qualified personnel within the oil and gas industry in western Canada, we implemented an Employee Retention Program in July 2006 for our existing employees, excluding officers and directors. Pursuant to the program, and based upon various conditions existing on July 1, 2007, including the market value of the Company's shares, we incurred additional compensation expense of $4.0 million. For the years ended December 31, 2006 and 2007, we recognized $1.4 million and $2.6 million respectively in stock-based compensation in relation to this program.

INCOME TAXES

Income taxes are recorded using the liability method of accounting. Future income taxes are calculated based on the difference between the accounting and income tax basis of an asset or liability. The classification of future income taxes between current and non-current is based upon the classification of the liabilities and assets to which the future income tax amounts relate. The classification of a future income tax amount as current does not imply a cash settlement of the amount within the following twelve month period.

CURRENT INCOME TAXES

No current income taxes were incurred in 2007 and 2006 primarily as a result of the elimination of federal capital tax effective January 1, 2006. Current taxes of $5 million in 2005, in addition to capital taxes, included $3 million related to the resolution of a Notice of Objection with respect to a corporate acquisition in a prior tax period. As a result of the reassessment resulting from resolution of the Notice of Objection, $7 million of tax deductible exploration expenses denied to the acquired corporation were added to our income tax pools as a positive offset to incurring the current liability. The resolution of this matter did not impact our total future income tax expense for 2006.

FUTURE INCOME TAXES

Future income taxes in 2007 included a $50 million recovery as a result of reductions in the federal corporate tax rates, which were enacted in the second and fourth quarter of 2007. The federal tax rate is to be reduced by 1.0% in 2008, 1.0% in 2009, 1.0% in 2010, 2.0% in 2011, and 3.5% in 2012. Future taxes in 2006 also included a $50 million recovery as a result of reductions in the federal and Alberta corporate tax rates, which were enacted in the second quarter of 2006.

CORPORATE TAX RATES

Years ended December 31,	**2007**	2006	2005
Statutory rate	**32.1%**	34.5%	37.6%
Effective rate	**(24.3)%**	(2.8)%	39.5%

A reconciliation of our effective tax rate to the statutory rate may be found in Note 16a to the consolidated financial statements.

TAX POOLS

The following table summarizes our estimated tax pool balances by classification.

As at January 1, 2008	Available Balance ($000s)	Maximum Annual Deduction
Canadian exploration expense and non-capital losses	$ 360,500	100%
Canadian development expense	367,241	30%
Canadian oil and natural gas property expense	74,070	10%
Undepreciated capital cost and financing costs	316,151	~ 25%
Total	**$ 1,117,962**	

A significant portion of our taxable income is generated by a wholly owned partnership. Consolidated earnings before income taxes include $149 million (2006 - $259 million) of partnership earnings that will be included in the following year's income for income tax purposes. Future income taxes include $44 million (2006 - $83 million) as a result of this deferral of partnership earnings.

Based upon planned capital expenditure programs and current commodity price assumptions, it appears we will not incur current income taxes until at least 2010.

Management's Discussion & Analysis

CAPITAL EXPENDITURES

SUMMARY OF CAPITAL EXPENDITURES

	2007		2006		2005	
Years ended December 31,	($000s)	%	($000s)	%	($000s)	%
Drilling and completions	**$ 226,789**	**59**	$ 294,197	60	$ 318,502	66
Land and seismic	**47,528**	**12**	59,905	12	55,469	11
Facilities	**111,215**	**29**	137,409	28	109,729	23
Sub-total	**$ 385,532**	**100**	$ 491,511	100	$ 483,700	100
Corporate acquisitions	**131,380**		–		–	
Acquisitions and divestments, net	**(229,391)**		34,394		28,575	
Sub-total	**$ 287,521**		$ 525,905		$ 512,275	
MPP	**4,796**		(31)		1,261	
Total capital expenditures	**$ 292,317**		$ 525,874		$ 513,536	

Capital spending in 2007 was directed towards the continued development of our core natural gas resource plays in southern and central Alberta. Overall, 2007 capital spending, before acquisitions and divestitures, decreased by 22% when compared to 2006. This reduction reflects the fewer number of wells drilled in 2007 versus the prior year as well as an overall reduction in certain service costs in 2007 as compared to 2006. We drilled 6% fewer wells in 2007 as compared to 2006, and drilling and completions expenditures declined by 23%, which implies an overall reduction in service costs of approximately 17%. Lower spending on land and seismic and facilities during 2007 also reflect the lower level of activity as compared to 2006.

During 2007, we pursued our strategy of divesting of non-focus assets and the redeployment of the proceeds into our focus area natural gas plays, including strategic acquisitions. We closed non-core property divestments, including our conventional light oil property at Worsley, for total net proceeds of $303.1 million. We also added to our core areas through a series of property acquisitions that totaled approximately $73.7 million, resulting in $229.4 million property divestments net of acquisitions. Through two corporate acquisitions, Stylus Energy Inc. and WIN Energy Corporation, we significantly expanded our presence in southern Alberta and the Foothills in 2007 at a total cost of $131.4 million.

During the second quarter of 2007, we undertook a major two week maintenance turn around at the Mazeppa gas plant. This scheduled maintenance, which is necessary every three years, accounts for the increased capital spending at Mazeppa when compared to 2006 and 2005.

Capital expenditures, before acquisitions and divestitures, in 2006 increased only marginally from 2005; however, they reflect overall cost inflation experienced in the industry during the year. We drilled a total of 274 net wells in 2006 at an average cost, to drill and complete, of $1,074,000 per well. In contrast, we drilled 334 net wells during 2005 at an average cost of $954,000 per well. Although not an entirely comparable analysis, as the mix of shallow, deep, and oil wells affected this comparison, this represented a 12.6% increase in drilling and completion costs, on a per well basis, in 2006 as compared to 2005.

Spending on production facilities increased $27.7 million in 2006 over 2005 and comprised 28% of our total capital program, before acquisitions and divestments as compared to 23% in 2005. Although we deferred a portion of our initial 2006 drilling program in deference to lower commodity prices and the inflationary cost environment, we continued with the majority of our planned expenditures in 2006 relating to equipment and facilities.

Liquidity and Capital Resources

As at December 31, ($000s, except where noted)	2007	2006	2005
Working capital deficiency [1]	$ **39,215**	$ 23,163	$ 62,116
Bank debt	**398,426**	328,000	177,900
Senior term notes	**433,762**	524,385	357,640
Total indebtedness	$ **871,403**	$ 875,548	$ 597,656
Shareholders' equity	$ **869,956**	$ 734,124	$ 596,336
Debt to adjusted cash flow from operations [2]	**4.2**	3.4	2.2
Debt to book capitalization	**49%**	54%	50%
Debt to market capitalization	**41%**	39%	22%

(1) Excludes unrealized risk management items net of related future income taxes.

(2) Based on trailing 12 month adjusted cash flow from operations.

SENIOR TERM NOTES

The Senior Notes are repayable in U.S. dollars and for 2007 are carried on the balance sheet at their Canadian dollar equivalent less related unamortized transaction costs. The 2005 and 2006 comparative amounts have not been adjusted to reflect the new accounting treatment. The Canadian dollar equivalent is determined based upon the Canadian/U.S. dollar exchange rate at December 31.

During the fourth quarter of 2007, we entered into foreign currency exchange contracts to purchase U.S.$450 million for C$436 million as at December 1, 2010, being the second call date on the Senior Notes. The Senior Notes are due on December 1, 2013. The foreign exchange contracts effectively fix the Canadian dollar repayment amount of the Senior Notes at $436 million through to December 1. 2010 and crystallized an unrealized foreign exchange gain of approximately $91.7 million.

The carrying value of the Senior Notes will continue to vary in relation to the Canadian/U.S. dollar exchange rate and any resulting unrealized foreign exchange gains or losses will be recognized. The variance in the carrying amount of the notes will largely be offset by the mark-to-market value of the foreign exchange contracts. Effectively, unrealized foreign exchange gains and losses resulting from translation of the notes will be offset by unrealized gains and losses on the foreign exchange contracts until December 1, 2010. At December 31, 2007 an additional accumulated gain of $14.1 million has been recorded on the foreign exchange contracts as outlined in Note 17(a)(iii) to the financial statements.

BANK DEBT

Bank debt is comprised of a syndicated credit facility with a current authorized limit of $500 million. The facility is a borrowing based facility with the borrowing base being determined based upon year end reserves. The facility is subject to review annually prior to the renewal date of July 4, 2008. We do not anticipate any reduction to the borrowing base and authorized credit facility amount given the increase in 2007 reserves over 2006.

Our corporate debt is structured to provide us with financial flexibility. Of our existing debt, 50% consists of Senior Notes that are not due until 2013, giving us the ability to draw on our senior secured credit facilities to assist in funding our planned 2008 capital program.

We have identified a number of non-core properties for disposition during 2008. We anticipate the proceeds from the sale of these properties to be approximately $250 million. Initially, the proceeds so generated will be applied to reduce our outstanding bank debt. Additionally, the authorized limit of $500 million may be reduced to recognize the reduction in associated reserves related to these dispositions. Any such potential change is expected to be minimal due to 2007 reserve additions.

We believe internally generated adjusted cash flow from operations and proceeds from planned property dispositions will be more than sufficient to fund our planned 2008 capital program. Excess funds will be used to reduce bank indebtedness.

Management's Discussion & Analysis

CONTRACTUAL OBLIGATIONS

As part of normal business, we have entered into arrangements and incurred obligations that will impact our future operations and liquidity, some of which are reflected as liabilities in the consolidated financial statements. The following table summarizes our contractual obligations as at December 31, 2007.

	Payments Due by Period				
($000s)	Less than 1 year	1-3 years	4-5 years	After 5 years	Total
Bank debt	–	$ 400,000	–	–	$ 400,000
Senior term notes	–	–	$ 436,388	–	436,388
Operating leases	$ 3,811	3,830	–	–	7,641
Office facilities	4,351	16,565	5,569	$ 33,414	59,899
MPP partnership distributions	9,172	3,057	–	–	12,229
Asset retirement obligations	2,818	3,910	7,203	232,631	246,562
Total	$ 20,152	$ 427,362	$ 449,160	$ 266,045	$ 1,162,719

We have the ability and the intention to extend the term of our bank debt and therefore repayment of the facility, although included in the schedule of contractual obligations, is not expected to occur.

Outlook and Guidance For 2008

The following section summarizes our plans and guidance for 2008 as announced in a news release dated January 23, 2008. We believe our budget to be achievable, however, certain events more fully described under "Recent Events", will impact our 2008 operations.

SUMMARY OF 2008 GUIDANCE

	2008 Budget Range
Capital expenditures *($millions)*	$410
Gross wells	350
Average production – total boe/d	36,000 to 37,000
Adjusted cash flow from operations *($millions)*	$245 to $255

Our 2008 projected adjusted cash flow from operations is based upon the following pricing assumptions:

	Benchmark	Realized
Natural gas	AECO Cdn $6.98/mcf	Cdn $6.95/mcf
Crude oil *($/bbl)*	WTI U.S. $81.00/bbl	Cdn $72.75/bbl

The average Canadian/U.S. exchange rate is budgeted at $1.00 U.S. = $1.00 Cdn.

Concurrent with strengthening commodity prices during the first part of 2008, we have systematically entered into a number of commodity hedge contracts as summarized in the Risk Management section of this MD&A and Note 17(a)(ii) to the financial statements. The effect of these contracts is an increase in projected 2008 cash flow of $10.8 million from the amount noted above. It is our intent to hedge approximately 50% of our gross production forward 12 to 18 months.

CASH FLOW SENSITIVITIES FOR 2008

($millions)	Change in Cash Flow
Change of Cdn $0.25/mcf in the benchmark AECO natural gas price	$ 14.0
Change of U.S. $1.00/bbl in the benchmark WTI oil price	$ 0.4

In the event of significant changes in commodity prices, operating and exploration costs, or an overall change in general economic or industry

conditions, we can readily amend our capital expenditure program as appropriate.

Recent Events

In response to concerns raised by a major shareholder of Compton, the Board of Directors of the Company, as announced in a news release dated February 27, 2008 will conduct a formal review of the Company's business plans and strategic alternatives. This will include exploring potential asset divestments, equity alternatives, strategic alliances, joint venture opportunities, mergers, or a corporate transaction. In the aforementioned news release, the Company cautioned shareholders that there is no assurance that the review will result in any specific transaction and no timetable had been set for its completion.

The Company has estimated that during 2008 direct costs and costs resulting from the process associated with shareholder activism will be approximately $22 million. Such costs will include additional legal fees, advisory fees and expenses, and employee retention costs. Such costs will be included in 2008 general and administrative expenses and will reduce cash flow from operations. Depending upon the outcome of the process the Company could incur additional cash outlays relating to change of control provisions applicable to the Company's Senior Notes, Mazeppa Processing Partnership arrangements, employee contracts, and additional advisory and legal fees.

At this stage, we are unable to predict the outcome of the review process and the direction that Compton may ultimately take. As events unfold, we will provide complete and timely updates.

Additional Disclosures

CONTROLS AND PROCEDURES

With respect to disclosure controls and procedures and internal control over financial reporting, we are required to comply with the U.S. Sarbanes-Oxley Act of 2002 and Canadian Multilateral Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. These regulations are substantially the same. However, the most significant difference is the U.S. requirement for the registered public accounting firm that audits our financial statements, included in our annual report, to issue an attestation report on our internal control over financial reporting. There is no corresponding Canadian attestation requirement.

There are certain procedural and wording differences between the U.S. and Canadian certifications. We have chosen to file the form of certification pursuant to Section 302 of the Sarbanes-Oxley Act with the U.S. Securities and Exchange Commission ("SEC") and Form 52-109 F1, Certification of Annual Filings, with the Canadian Securities Administrators ("CSA").

We have complied with both the U.S. and Canadian requirements in respect of disclosure controls and procedures and internal control over financial reporting and our report is below.

MANAGEMENT'S EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

The term "disclosure controls and procedures" is defined, under Rule 13a-15(d) of the U.S. Exchange Act of 1934, as controls and other procedures that are designed to ensure both non-financial and financial information required to be disclosed by us in our periodic reports is recorded, processed, summarized, and reported within the time periods required, and this information is accumulated and communicated to management as appropriate, to allow timely decisions regarding required disclosures. The definition of disclosure controls and procedures with respect to Canadian Multilateral Instrument 52-109 is substantially the same.

As indicated in our certifications filed with the SEC and CSA, we completed an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures as of December 31, 2007, under the supervision and with the participation of our Management, including our President & CEO and VP Finance & CFO. Based upon our evaluation, we concluded our disclosure controls and procedures were effective.

Management's Discussion & Analysis

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management, including our President & CEO and VP Finance & CFO, is responsible for establishing and maintaining adequate internal control over financial reporting. The term "internal control over financial reporting" is defined, under both Rule 13a-15(f) of the U.S. Exchange Act of 1934 and Canadian Multilateral Instrument 52-109, as processes designed by, or under the supervision of, our principal executive and principal financial officers, and effected by our board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of our financial statements for external purposes in accordance with GAAP. These controls would include policies and procedures that:

- Pertain to the maintenance of our records, that accurately and fairly reflect the transactions affecting, and dispositions of, our assets;
- Provide reasonable assurance that transactions are recorded to be able to prepare our financial statements in accordance with GAAP, and that our receipts and expenditures are made only in accordance with authorizations of our management and directors; and
- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of our assets, which could have a material effect on our financial statements.

We completed an evaluation of the effectiveness of the design and operation of our internal control over financial reporting under the supervision, and with the participation, of our Management, including our President & CEO and VP Finance & CFO. We conducted our evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control – Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission, also known as COSO. Based upon our evaluation, we have concluded, as of December 31, 2007, internal control over financial reporting was effective.

The effectiveness of internal control over financial reporting as of December 31, 2007 was audited by Grant Thornton LLP, Chartered Accountants, the independent registered public accounting firm, which also audits our financial statements. They have issued their Independent Auditors' Report which is included in this Annual Report.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

During the quarter ended March 31, 2007, we made two material changes to internal control over financial reporting. On March 1, 2007 we converted our production accounting and royalty management information systems. These changes were implemented to improve both operational efficiencies and internal controls. These conversions were not due to any identified internal control weaknesses.

During the quarter ended December 31, 2007, we made one material change to internal control over financial reporting. On October 15, 2007, we implemented our substantially re-engineered capital expenditure approval and tracking business process. This included improved policies and procedures as well as new workflow software to support those policies and procedures. This change was implemented to improve operational effectiveness and efficiency as well as remediate internal control deficiencies.

These changes were subject to our change management procedures which are effective.

There were no other changes during the year ended December 31, 2007 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

CRITICAL ACCOUNTING ESTIMATES

Accounting estimates require us to make assumptions regarding matters that are uncertain at the time the estimate is made and may have a material impact on our financial condition. A comprehensive discussion of our significant accounting policies may be found in Note 1 to the consolidated financial statements.

OIL AND NATURAL GAS RESERVES

The independent petroleum engineering and geological consulting firm of Netherland, Sewell & Associates, Inc. evaluated and reported on 96% of our oil and natural gas reserves. The remainder was internally evaluated.

The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. We expect that our estimates of reserves will change with updated information from the results of future drilling, testing, or production levels. Such revisions could be upwards or downwards. Reserve estimates have a material impact on depletion and depreciation, asset retirement obligations, and impairment costs, all of which could possibly have a material impact on our consolidated net earnings.

DEPLETION

Capitalized costs and estimated future expenditures to develop proved reserves, including abandonment costs, are depleted based on the proportion of proved oil and natural gas reserves produced during the year compared to estimated total proved reserves. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If it is determined that properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized.

In 2007, we incurred $151 million of depletion and depreciation. If our proved reserves were to increase by 5%, our depletion and depreciation expense would decrease by $1.8 million and consolidated net earnings after tax would increase by $1.4 million. If our proved reserves were to decrease by 5%, our depletion and depreciation expense would increase by $2.0 million and consolidated net earnings after tax would decrease by $1.5 million.

IMPAIRMENT

In applying the full cost method of accounting, we periodically calculate a ceiling or limitation on the amount that property and equipment may be carried for on the consolidated balance sheets. An impairment exists if the undiscounted future net cash flows from proved reserves at future commodity prices plus the cost of undeveloped properties is less than the carrying value of the capitalized costs. As at December 31, 2007, the ceiling amount calculated was $2.4 billion (2006 - $2.7 billion) in excess of the carrying value of the costs capitalized.

If an impairment is found to exist, the impaired properties are written down to their fair value. The fair value of the assets is calculated based on future net cash flows from proved plus probable reserves, discounted at a risk free interest rate using future commodity prices, plus the cost of undeveloped properties. An impairment may result in a material loss for a particular period; however, future depletion and depreciation expense would be reduced as a result.

Assumptions about reserves and future prices are required to calculate future net cash flows. The assumptions made to estimate reserves have been discussed above. There is significant uncertainty regarding forecasting future commodity prices due to economic and political uncertainties. Future prices are derived from a consensus of price forecasts among recognized reserve evaluators. Estimates of future cash flows assume a long term price forecast and current operating costs per boe plus an inflation factor.

Management's Discussion & Analysis

It is difficult to determine and assess the impact of a decrease in proved reserves on impairment. The relationship between reserve estimates and the estimated undiscounted cash flows, and the nature of the property-by-property impairment test is complex. As a result, it is not possible to provide a reasonable sensitivity analysis of the impact that a reserve estimate decrease would have on impairment. No material downward revisions to our reserves are anticipated.

ASSET RETIREMENT OBLIGATION

We recognize the fair value of estimated asset retirement obligations on the consolidated balance sheet when a reasonable estimate of fair value can be made. Asset retirement obligations include those legal obligations where we will be required to retire tangible long term assets such as well sites, pipelines, and facilities. The asset retirement cost, equal to the initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long term assets. Increases in the asset retirement obligations resulting from the passage of time are recorded as accretion of asset retirement obligations in the consolidated statement of earnings. Amounts recorded for asset retirement obligations are subject to uncertainty associated with the method, timing, and extent of future retirement activities. Actual payments to settle the obligations may differ from estimated amounts.

RECENT ACCOUNTING PRONOUNCEMENTS

On January 1, 2008, the Company will adopt the following CICA Handbook Sections:

Section 3031, *"Inventories"* which replaces the existing standard. The requirements include the consistent grouping of like assets and the application of the first-in-first-out or weighted average cost formula methodologies.

Section 1400, *"General Standards of Financial Statement Presentation"* which requires assessing and disclosing the Company's ability to continue as a going concern.

Section 3862, *"Financial Instruments – Disclosures"* and Section 3863, *"Financial Instruments – Presentation"*. These new standards will require increased disclosure of financial instruments with particular emphasis on the risks associated with recognized and unrecognized financial instruments and how those risks are managed.

Section 1535, *"Capital Disclosures"*, requiring disclosure of information about an entity's capital and the objectives, policies, and processes for managing capital.

The adoption of these standards is not expected to have a material impact on the Company's consolidated financial statements.

On January 1, 2009 the Company will be required to adopt CICA Handbook Section 3064, *"Intangible Assets"*. The new section established standards for the recognition, measurement, and disclosure of goodwill and intangible assets and replaces the existing Handbook Section 3062, *"Goodwill and Other Intangible Assets"* and Section 3450, *"Research and Development Costs"*. Intangible assets associated with the exploration and development of oil and gas assets are specifically excluded under the new standard. The Company is evaluating the implications of this adoption, but expects no material impact on the consolidated financial statements.

On January 10, 2006, the CICA Accounting Standards Board ("AcSB") ratified a new strategic plan that would see the convergence of Canadian Generally Accepted Accounting Principles ("GAAP") with International Financial Reporting Standards ("IFRS") within 5 years. In March 2007, the AcSB released an *"Implementation Plan for Incorporating IFRSs into Canadian GAAP"*, which assumed a convergence date of January 1, 2011. The AcSB confirmed this date in February 2008. The Company continues to monitor and assess the consequences of convergence on the consolidated financial statements as they could have a material impact.

RISK MANAGEMENT

Our operations are subject to risks inherent to the oil and natural gas industry. We are exposed to financial risks including fluctuations in commodity prices, currency exchange rates, interest rates, credit ratings, and changing expenditure costs due to shifts in market conditions. We take specific measures to manage these risks, particularly those impacting adjusted cash flow from operations.

A more detailed discussion of risk factors is presented in our most recent Annual Information Form, filed with securities regulatory authorities on or before March 31, 2008 on www.sedar.com.

COMMODITY PRICE RISK MANAGEMENT

We enter into commodity price contracts to actively manage risk associated with price volatility to protect adjusted cash flow from operations required to fund our capital program. We use fixed price and costless collar contracts as well as balancing physical and financial contracts in terms of volumes, timing of performance, and delivery obligations to manage risk. Net open positions may exist or may be established to take advantage of market conditions. Net earnings for the year ended December 31, 2007, include realized and unrealized loss of $1.6 million (2006 - $65.0 million gain) on these transactions.

The following table outlines commodity hedge transactions in place at December 31, 2007 together with transactions entered into subsequent to the year end:

Commodity	Term	Amount mcf/d	Average Price $/mcf	Index
Natural gas				
Collar	Nov. 2007 - March 2008	9,524	$8.27 - $10.50	AECO
Collar	April 2008 - Oct. 2008	52,381	$7.33 - $8.48	AECO
Fixed	April 2008 - Oct. 2008	19,048	$7.86	AECO
Collar	Nov. 2008 - March 2009	28,571	$8.40 - $10.00	AECO
Fixed	Nov. 2008 - March 2009	9,524	$8.51	AECO
Crude oil				
Fixed	March 2008 - Dec. 2008	1,000 bbls/d	U.S.$93.00/bbl	WTI

FOREIGN CURRENCY EXCHANGE RATE RISK MANAGEMENT

Our 7.625% Senior Notes due December 1, 2013 and semi-annual interest obligations thereon are payable in U.S. dollars. Accordingly, we are exposed to fluctuations in the exchange rate between the Canadian and the U.S. dollar. To manage this risk we entered into a series of foreign exchange contracts relating to the principle amount of the Notes, effectively fixing the liability at $436 million Canadian through to December 1, 2010, being the second call date on the Notes. Additionally, we entered into a series of foreign exchange contracts relating to the interest obligations associated with the Notes through to December 1, 2010.

We are also exposed to fluctuations in the exchange rate between the Canadian dollar and the U.S. dollar. Commodity prices are based on U.S. dollar benchmarks that result in our realized price being influenced by the Canadian/U.S. currency exchange rate. Should the Canadian dollar strengthen compared to the U.S. dollar we will experience a negative effect on net earnings. Conversely, should the Canadian dollar weaken compared to the U.S. dollar we will experience a positive effect on net earnings.

Management's Discussion & Analysis

INTEREST RATE RISK MANAGEMENT

We are exposed to fluctuations in interest rates on corporate borrowings. To manage this risk we attempt to achieve a balance between fixed and floating interest rate debt instruments. Our Senior Notes bear a fixed interest charge of 7.625% and our borrowings under our syndicated credit facility incur floating rate interest charges. At year end approximately 52% of our total corporate debt incurred fixed rate interest charges and the balance incurred floating rate charges.

Concurrent with the closing of our 9.90% Senior Notes offering in May of 2002, we entered into a cross currency interest rate swap. The swap, which converted fixed rate U.S. dollar interest obligations into floating rate Canadian dollar interest obligations, was entered into to fix the exchange rate on interest payments and take advantage of lower floating interest rates. On repurchase of the majority of 9.90% Senior Notes in November 2005, we elected not to collapse the swap and incur the then associated costs of $12 million. The swap remains outstanding and at December 31, 2007, we valued the liability relating to future unrealized losses on the swap arrangement to be $10.4 million (2006 - $11 million) determined on a mark-to-market basis. The loss associated with the swap has resulted primarily from the strengthening of the Canadian dollar. Should the Canadian dollar continue to increase against the U.S. dollar, the loss could increase further; alternatively if the Canadian dollar were to weaken the loss would be reduced. Cash settlements of the swap positions are made semi-annually and losses realized will be recorded over the remaining term of the swap agreement which expires in May 2009.

SELECTED QUARTERLY INFORMATION

The following tables set out selected quarterly financial information for the last two fiscal years.

2007

		Three Months Ended			Year Ended
($000s, except where noted)	Mar. 31, 2007	Jun. 30, 2007	Sep. 30, 2007	Dec. 31, 2007	Dec. 31, 2007
Average production *(boe/d)*	33,316	28,918	30,440	32,646	31,326
Average pricing *($/boe)*	$ 46.98	$ 47.94	$ 38.56	$ 41.94	$ 43.82
Total revenue	$ 140,877	$ 126,171	$ 107,980	$ 125,959	$ 500,987
Adjusted cash flow from operations	$ 68,783	$ 48,582	$ 33,133	$ 45,696	$ 196,194
Per share: basic	$ 0.53	$ 0.38	$ 0.26	$ 0.35	$ 1.52
diluted	$ 0.52	$ 0.36	$ 0.25	$ 0.35	$ 1.48
Adjusted net earnings from operations	$ 17,933	$ 7,364	$ (1,994)	$ (2,017)	$ 21,286
Net earnings (loss)	$ 13,719	$ 45,307	$ 19,782	$ 50,457	$ 129,266
Per share: basic	$ 0.11	$ 0.35	$ 0.15	$ 0.39	$ 1.00
diluted	$ 0.10	$ 0.34	$ 0.15	$ 0.38	$ 0.98

September and October of 2007 were our busiest drilling months on record since Company inception. These high activity levels generated production growth of 7% from the third quarter to the fourth quarter of 2007. Strengthening commodity prices together with increased production volumes resulted in a 17% increase in fourth quarter revenue and a 38% increase in adjusted cash flow from operations over the third quarter of 2007. Revenue and net earnings were lower during the third quarter of 2007 due primarily to lower realized prices.

2006

($000s, except where noted)	Three Months Ended Mar. 31, 2006	June 30, 2006	Sept. 30, 2006	Dec. 31, 2006	Year Ended Dec. 31, 2006
Average production *(boe/d)*	34,029	32,645	32,843	33,245	33,187
Average pricing *($/boe)*	$ 48.58	$ 45.37	$ 42.03	$ 42.60	$ 44.65
Total revenue	$ 148,779	$ 134,778	$ 126,991	$ 130,289	$ 540,837
Adjusted cash flow from operations	$ 73,596	$ 67,326	$ 60,120	$ 55,263	$ 256,305
Per share: basic	$ 0.58	$ 0.53	$ 0.47	$ 0.43	$ 2.01
diluted	$ 0.55	$ 0.50	$ 0.45	$ 0.42	$ 1.92
Adjusted net earnings from operations	$ 22,249	$ 17,947	$ 13,150	$ 11,822	$ 65,168
Net earnings (loss)	$ 38,002	$ 68,744	$ 30,717	$ (10,037)	$ 127,426
Per share: basic	$ 0.30	$ 0.54	$ 0.24	$ (0.08)	$ 1.00
diluted	$ 0.28	$ 0.51	$ 0.23	$ (0.08)	$ 0.95

During the second half of 2006, lower realized commodity prices from those experienced during the first half of the year resulted in reduced revenue, cash flow, and adjusted net earnings from operations. Production increases in the third and fourth quarter were more than offset by the reduction in commodity prices. The negative effect of lower commodity prices on cash flow was reduced by realized gains of $36 million from risk management activities. Net earnings for the nine months ended September 30, 2006 benefited from an unrealized foreign exchange gain of $19.1 million, after tax, and an income tax recovery of $35 million. Net earnings in the fourth quarter were negative due to the reversal of unrealized foreign exchange gains recorded in prior quarters, as the result of the weakening of the Canadian dollar compared to the U.S. dollar.

SELECTED ANNUAL INFORMATION

Years ended December 31, ($000s)	**2007**	2006	2005
Total revenue	**$ 500,987**	$ 540,837	$ 564,241
Net earnings	**$ 129,266**	$ 127,426	$ 81,326
Per share: basic	**$ 1.00**	$ 1.00	$ 0.65
diluted	**$ 0.98**	$ 0.95	$ 0.62
Total assets	**$ 2,254,587**	$ 2,145,472	$ 1,758,098
Total long term financial liabilities	**$ 832,188**	$ 852,385	$ 535,540

Total revenue in 2007 was lower than 2006 due to lower oil prices and slightly lower production volumes arising from the disposition of our conventional oil asset Worsley.

Total revenue in 2006 was marginally lower than 2005 with increases in production being more than offset by reduced commodity prices. Net earnings in 2006 increased $46.1 million over 2005 primarily as a result of risk management gains that offset the reduction in revenue and increases in expenses. Long term financial obligation in 2006 increased over 2005 as a result of increased borrowings to fund the capital programs.

Management's Discussion & Analysis

TRADING AND SHARE STATISTICS

As at March 10, 2008 there were 129,194,721 common shares outstanding and 12,314,907 stock options.

	2007		2006		2005[1]	
	TSX ($Cdn)	**NYSE ($US)**	TSX ($Cdn)	NYSE ($US)	TSX ($Cdn)	NYSE ($US)
Average daily trading volume *(000s)*	**485,027**	**213,044**	545,489	115,450	736,416	138,288
Share price *($/share)*						
High	**$13.19**	**$12.16**	$19.24	$16.74	$18.66	$16.11
Low	**$7.40**	**$7.70**	$10.20	$9.04	$9.80	$14.15
Close	**$9.14**	**$9.20**	$10.65	$9.12	$17.10	$14.65
Market capitalization at December 31 *($000s)*	**$1,179,958**		$1,368,557		$2,176,197	
Shares outstanding *(000s)*	**129,098**		128,503		127,263	

Trading on the New York Stock Exchange commenced December 5, 2005.

Further Information

Additional information, including our Annual Information Form, is available on the Canadian Securities Administrators' System for Electronic Document Analysis and Retrieval ("SEDAR") at www.sedar.com.

Compton's Mazeppa Gas Plant

Financial Reports

Management's Report

TO THE SHAREHOLDERS OF COMPTON PETROLEUM CORPORATION

The accompanying Consolidated Financial Statements of Compton Petroleum Corporation (the "Company") are the responsibility of Management and have been prepared by Management in accordance with Canadian generally accepted accounting principles and policies stated in the notes to the Consolidated Financial Statements. Financial information contained throughout the annual report to shareholders is consistent with these financial statements.

The Company's Board of Directors has approved the Consolidated Financial Statements on the recommendation of the Audit Finance and Risk Committee, which has a written mandate that complies with the current requirements of Canadian securities legislation and the United States Sarbanes-Oxley Act of 2002.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedure are designed to provide reasonable assurance that information required to be disclosed in reports filed with securities regulatory authorities is recorded, processed, summarized and presented in accordance with Canadian and United States securities laws. Management has evaluated the effectiveness of the Company's design and operation of disclosure controls and procedures as of December 31, 2007 and has concluded that the Company's disclosure controls and procedures were effective.

MANAGEMENT'S ASSESSMENT OF INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is also responsible for establishing and maintaining adequate internal control over the Company's financial reporting. Internal control, as more fully described in Management's Discussion and Analysis, includes policies and procedures designed to provide reasonable assurance relating to the reliability, completeness and timeliness of financial reporting. Management has assessed the effectiveness of the design and operation of internal control over financial reporting based on the Internal Control Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission, ("COSO"). Based on this assessment, Management has concluded that, as of December 31, 2007, internal control over financial reporting was effective.

Grant Thornton LLP, an independent firm of chartered accountants, appointed by shareholders, has provided independent opinions on both the Consolidated Financial Statements and the Company's internal control over financial reporting as at December 31, 2007.

E.G. SAPIEHA, C.A.
President & Chief Executive Officer

N.G. KNECHT, C.A.
Vice President Finance & Chief Financial Officer

March 24, 2008

Independent Auditors' Report

TO THE SHAREHOLDERS OF COMPTON PETROLEUM CORPORATION

We have audited the accompanying consolidated balance sheets of Compton Petroleum Corporation as at December 31, 2007 and 2006 and the consolidated statements of earnings and other comprehensive income, retained earnings, and cash flow for each of the three years in the period ended December 31, 2007. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. Our audits of the financial statements include examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. A financial statement audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as at December 31, 2007 and 2006 and the results of its operations and cash flow for each of the three years in the period ended December 31, 2007 in accordance with Canadian generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 24, 2008 expressed an unqualified opinion on the effectiveness of internal controls over financial reporting.

Grant Thornton LLP

Calgary, Canada
March 24, 2008

Grant Thornton LLP
Chartered Accountants

Financial Reports

Independent Auditors' Report

TO THE SHAREHOLDERS OF
COMPTON PETROLEUM CORPORATION

We have audited Compton Petroleum Corporation's internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Compton Petroleum Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying management's report. Our responsibility is to express an opinion on Compton Petroleum Corporation's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Compton Petroleum Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control–Integrated Framework issued by COSO.

We also have audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of the Company as at December 31, 2007 and 2006 and the consolidated statements of earnings and other comprehensive income, retained earnings and cash flow for each of the three years in the period ended December 31, 2007, and our report dated March 24, 2008, expressed an unqualified opinion on those financial statements.

Grant Thornton LLP

Calgary, Canada
March 24, 2008

Grant Thornton LLP
Chartered Accountants

Consolidated Balance Sheets

As at December 31, (thousands of dollars)		2007	2006
ASSETS			
Current			
Cash		$ 8,665	$ 11,876
Accounts receivable		80,331	83,535
Unrealized risk management gain	*(Note 17a (i))*	1,835	22,625
Other current assets		19,772	22,869
Future income taxes	*(Note 16b)*	2,606	1,479
		113,209	142,384
Property and equipment	*(Note 5)*	2,116,834	1,977,062
Goodwill	*(Note 3)*	9,933	7,914
Other assets	*(Note 9)*	291	14,144
Unrealized risk management gain	*(Note 17a (i))*	14,320	–
Deferred risk management loss	*(Note 2b)*	–	3,968
		$ 2,254,587	$ 2,145,472
LIABILITIES			
Current			
Accounts payable		$ 147,983	$ 141,443
Unrealized risk management loss	*(Note 17a (i))*	8,832	4,604
Future income taxes	*(Note 16b)*	542	7,269
		157,357	153,316
Bank debt	*(Note 6)*	398,426	328,000
Senior term notes	*(Note 7)*	433,762	524,385
Asset retirement obligations	*(Note 11)*	36,696	29,791
Unrealized risk management loss	*(Note 17a (i))*	1,585	6,816
Future income taxes	*(Note 16b)*	293,494	302,690
Non-controlling interest	*(Note 4)*	63,311	66,350
		1,384,631	1,411,348
SHAREHOLDERS' EQUITY			
Capital stock	*(Note 12b)*	235,871	231,992
Contributed surplus	*(Note 13a)*	24,233	16,974
Retained earnings		609,852	485,158
		869,956	734,124
		$ 2,254,587	$ 2,145,472

Commitments and contingent liabilities *(Note 19)*

Subsequent events *(Note 20)*

On behalf of the Board

M.F. Belich, Q.C. *(signed)*
Director

J.A. Thomson, C.A. *(signed)*
Director

See accompanying notes to the consolidated financial statements.

Consolidated Financial Statements

Consolidated Statements of Earnings and Other Comprehensive Income

Years ended December 31, (thousands of dollars, except per share data)		2007	2006	2005
Revenue				
Oil and natural gas revenues		$ 500,987	$ 540,837	$ 564,241
Royalties		(102,678)	(123,677)	(132,717)
		398,309	417,160	431,524
Expenses				
Operating		101,478	102,643	73,164
Transportation		12,615	12,564	10,858
General and administrative		31,328	26,231	21,223
Interest and finance charges	*(Note 8)*	63,493	54,075	34,951
Tender costs		–	–	20,750
Depletion and depreciation		151,411	143,057	105,504
Foreign exchange gain	*(Note 10)*	(78,717)	(891)	(7,353)
Accretion of asset retirement obligations	*(Note 11)*	2,718	2,257	1,975
Stock-based compensation	*(Notes 13a and c)*	11,034	10,488	5,903
Risk management (gain) loss	*(Note 17b)*	(6,014)	(63,721)	19,302
		289,346	286,703	286,277
Earnings before taxes and non-controlling interest		108,963	130,457	145,247
Income taxes	*(Note 16a)*			
Current		17	44	5,071
Future		(26,452)	(3,636)	52,317
		(26,435)	(3,592)	57,388
Earnings before non-controlling interest		135,398	134,049	87,859
Non-controlling interest	*(Note 4)*	6,132	6,623	6,533
Net earnings		129,266	$ 127,426	$ 81,326
Other comprehensive income		–		
Comprehensive income		$ 129,266		
Net earnings per share	*(Note 14)*			
Basic		$ 1.00	$ 1.00	$ 0.65
Diluted		$ 0.98	$ 0.95	$ 0.62

Consolidated Statements of Retained Earnings

Years ended December 31, (thousands of dollars)		2007	2006	2005
Retained earnings, beginning of year				
As previously reported		$ 485,158	$ 360,719	$ 284,712
Accounting policy adjustment	*(Note 2)*	(1,320)	–	–
As adjusted		483,838	360,719	284,712
Net earnings		129,266	127,426	81,326
Premium on redemption of shares	*(Note 12b)*	(3,252)	(2,987)	(5,319)
Retained earnings, end of year		$ 609,852	$ 485,158	$ 360,719

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flow

Years ended December 31, (thousands of dollars)		2007	2006	2005
Operating activities				
Net earnings		$ 129,266	$ 127,426	$ 81,326
Amortization of deferred charges and other		3,417	1,996	2,190
Tender costs		–	–	20,750
Depletion and depreciation		151,411	143,057	105,504
Accretion of asset retirement obligations		2,718	2,257	1,975
Unrealized foreign exchange gain		(79,740)	(665)	(7,808)
Future income taxes		(26,452)	(3,636)	52,317
Unrealized risk management (gain) loss		5,467	(27,522)	10,171
Stock-based compensation		8,416	9,121	5,903
Asset retirement expenditures		(4,441)	(2,352)	(749)
Non-controlling interest		6,132	6,623	6,533
		196,194	256,305	278,112
Change in non-cash working capital	*(Note 18)*	(23,366)	19,823	6,612
		172,828	276,128	284,724
Financing activities				
Issuance (repayment) of bank debt		70,426	152,100	(42,100)
Issuance of senior notes		–	174,930	353,130
Issue costs on senior notes		–	(3,408)	(12,670)
Redemption of senior notes		–	(7,520)	(199,973)
Proceeds from share issuances, net		3,446	4,672	89,752
Distributions to partner		(9,171)	(9,171)	(9,172)
Redemption of common shares		(3,976)	(3,433)	(6,118)
		60,725	308,170	172,849
Investing activities				
Property and equipment additions		(391,070)	(490,429)	(484,213)
Corporate acquisitions	*(Note 3)*	(104,705)	–	–
Property acquisitions		(66,808)	(34,444)	(28,575)
Property dispositions		307,527	1,350	–
Change in non-cash working capital	*(Note 18)*	18,292	(57,853)	54,101
		(236,764)	(581,376)	(458,687)
Change in cash		(3,211)	2,922	(1,114)
Cash, beginning of year		11,876	8,954	10,068
Cash, end of year		$ 8,665	$ 11,876	$ 8,954

See accompanying notes to the consolidated financial statements.

Notes to the Consolidated Financial Statements

December 31, 2007

(Tabular amounts in thousands of dollars, unless otherwise stated)

1. Significant accounting policies

Compton Petroleum Corporation (the "Company" or "Compton") is in the business of the exploration for and production of petroleum and natural gas reserves in the Western Canada Sedimentary Basin.

A) Basis of presentation

The consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in Canada within the framework of the accounting policies summarized below. Information prepared in accordance with accounting principles generally accepted in the United States is included in Note 21.

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. The consolidated financial statements also include the accounts of Mazeppa Processing Partnership in accordance with Accounting Guideline 15 ("AcG-15") "Consolidation of Variable Interest Entities", as outlined in Note 4.

All amounts are presented in Canadian dollars unless otherwise stated.

B) Measurement uncertainty

The timely preparation of financial statements requires that Management make estimates and assumptions and use judgment regarding the measurement of assets, liabilities, revenues, and expenses. Such estimates relate primarily to transactions and events that have not settled as of the date of the financial statements. Accordingly, actual results may differ materially from estimated amounts as future confirming events occur.

Amounts recorded for depletion and depreciation, and amounts used in impairment test calculations are based upon estimates of petroleum and natural gas reserves and future costs to develop those reserves. By their nature, these estimates of reserves, costs, and related future cash flows are subject to uncertainty, and the impact on the consolidated financial statements of future periods could be material.

The calculation of asset retirement obligations include estimates of the ultimate settlement amounts, inflation factors, credit adjusted discount rates, and timing of settlement. The impact of future revisions to these assumptions on the consolidated financial statements of future periods could be material.

The amount of stock based compensation expense is subject to uncertainty and the Company's best estimate of whether or not performance will be achieved and obligations incurred.

The values of pension assets and obligations and the amount of pension costs charged to net earnings depend on certain actuarial and economic assumptions which by their nature are subject to measurement uncertainty.

C) Property and equipment

I) *Capitalized costs*

The Company follows the full cost method of accounting for its petroleum and natural gas operations within one Canadian cost centre. Under this method all costs related to the exploration for and development of petroleum and natural gas reserves are capitalized. Costs include lease acquisition costs, geological and geophysical expenses, costs of drilling both producing and non-producing wells, production facilities, future asset retirement costs, and certain general and administrative expenses directly related to exploration and development activities.

Proceeds from the sale of properties are applied against capitalized costs, without any gain or loss being realized, unless such sale would significantly alter the rate of depletion and depreciation.

Expenditures related to renewals or betterments that improve the productive capacity or extend the life of an asset are capitalized. Maintenance and repairs, other than major turnaround costs, are expensed as incurred. Major turnaround costs are included in property and equipment when incurred and charged to depletion and depreciation in the consolidated statement of earnings and other comprehensive income over the estimated period of time to the next scheduled turnaround.

II) DEPLETION AND DEPRECIATION

Depletion and depreciation of property and equipment is provided using the unit-of-production method based upon estimated proved petroleum and natural gas reserves. The costs of significant undeveloped properties are excluded from costs subject to depletion until it is determined whether or not proved reserves are attributable to the properties or impairment has occurred. Estimated future costs to be incurred in developing proved reserves are included in costs subject to depletion and estimated salvage values are excluded from costs subject to depletion. For depletion and depreciation purposes, relative volumes of natural gas production and reserves are converted at the energy equivalent conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil.

Depreciation of certain midstream facilities is provided for on a straight line basis over 30 years and depreciation of office equipment is provided for on a declining balance basis using rates which range from 20% to 30% per year.

III) IMPAIRMENT TEST

At each reporting period the Company performs an impairment test to determine the recoverability of capitalized costs associated with reserves. An impairment loss is recognized when the carrying amount of a cost centre is not recoverable. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves plus the costs of unproved properties. If the sum of the cash flows is less than the carrying amount, the impairment loss is limited to the amount by which the carrying amount exceeds the sum of the fair value of discounted proved and probable reserves and the costs of unproved properties that have been subject to a separate impairment test and contain no probable reserves.

IV) ASSET RETIREMENT OBLIGATIONS

The Company recognizes the present value of estimated asset retirement obligations on the consolidated balance sheet when a reasonable estimate can be made. Asset retirement obligations include those legal obligations where the Company will be required to retire tangible long-lived assets such as well sites, pipelines, and facilities. The asset retirement cost, equal to the initial estimated present value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. Changes in the estimated obligation resulting from revisions to estimated timing or amount of undiscounted cash flows are recognized as a change in the asset retirement obligation and the related asset retirement cost.

Asset retirement costs are amortized using the unit-of-production method and are included in depletion and depreciation in the consolidated statement of earnings and other comprehensive income. Increases in the asset retirement obligations resulting from the passage of time are recorded as accretion of asset retirement obligations in the consolidated statement of earnings and other comprehensive income.

Actual expenditures incurred are charged against the accumulated obligation.

V) INVENTORIES

Physical inventory held for exploration, development, and operating activities is included in property and equipment and is valued at estimated realizable value.

Notes to the Consolidated Financial Statements

D) GOODWILL

Goodwill is recorded on a corporate acquisition when the purchase price is in excess of the fair values assigned to assets acquired and liabilities assumed. Goodwill is not amortized and an impairment test is performed at least annually to evaluate the carrying value. To assess impairment, the fair value of the consolidated entity, excluding the Mazeppa Processing Partnership, is determined and compared to the carrying value. If the fair value is less than the carrying value then a second test is performed to determine the amount of the impairment. Any loss recognized is equal to the difference between the implied fair value and the carrying value of the goodwill.

E) FINANCIAL INSTRUMENTS AND DERIVATIVES

On January 1, 2007 the Company adopted the Canadian Institute of Chartered Accountants ("CICA") four new accounting standards: Handbook Section 1530, *"Comprehensive Income"*, Handbook Section 3855, *"Financial Instruments – Recognition and Measurement"*, Handbook Section 3861, *"Financial Instruments – Disclosure and Presentation"* and Handbook Section 3865, *"Hedges"*. The adoption of these standards resulted in accounting changes, the impact of which are disclosed in Note 2 to these consolidated financial statements.

Financial instruments are any contract that gives rise to a financial asset of one party and a financial liability or equity instrument of another party. Financial instruments were identified by the Company through a review of typical financial transactions and risk management activities. The Company also reviewed non-financial contracts, entered into subsequent to January 1, 2003, for potential embedded derivatives. Once identified, the financial instruments were classified and measured as disclosed below.

Financial instruments are measured at fair value on initial recognition of the instrument except in specific circumstances. Measurement in subsequent periods depends on whether the financial instrument has been classified as "held for trading", "available for sale", "held to maturity", "loans and receivables" or "other financial liabilities" as defined by the standards.

Financial assets and financial liabilities "held for trading" are measured at fair value with changes in those fair values recognized in net earnings. Financial assets "available for sale" are measured at fair value, with changes in those fair values recognized in other comprehensive income. Financial instruments "held to maturity", "loans and receivables" and "other financial liabilities" are measured at amortized cost using the effective interest method.

Cash, and deposits included in other current assets, are classified as "held for trading" and are measured at carrying value which approximates fair value due to the short term nature of these instruments. Investments included in other current assets are designated as "held for trading", accounts receivable are classified as "loans and receivables" and accounts payable, bank debt and senior term notes are classified as "other financial liabilities". Transaction costs, premiums and discounts associated with the issuance of senior term notes are netted against the notes and amortized to earnings using the effective interest method.

Derivative financial instruments are classified as "held for trading" and are recorded at fair value based on quoted market prices or third party market indications and forecasts. Fluctuations are recorded in earnings as risk management gains and losses during each reporting period. The Company uses derivative financial instruments for non-trading purposes to manage fluctuations in commodity prices, foreign currency exchange rates, and interest rates as outlined in Note 17. The Company does not designate any of its current risk management activities as accounting hedges.

F) JOINT OPERATIONS

Certain petroleum and natural gas activities are conducted jointly with others. These consolidated financial statements reflect only the Company's proportionate interest in such activities.

G) EARNINGS PER SHARE AMOUNTS

The Company uses the treasury stock method to determine the dilutive effect of stock options. This method assumes that proceeds received from the exercise of in-the-money stock options are used to repurchase common shares at the average market price for the period. Basic net earnings per common share are determined by dividing net earnings by the weighted average number of common shares outstanding during the period. Diluted earnings per share are computed by giving effect to the potential dilution that would occur if stock options were exercised.

H) INCOME TAXES

Income taxes are recorded using the liability method of accounting. Future income taxes are calculated based on the difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates. Changes in income tax rates are reflected in the period in which the rates are substantively enacted.

I) REVENUE RECOGNITION

Revenue associated with the production and sale of crude oil, natural gas, and natural gas liquids owned by the Company is recognized when title passes to the customer and delivery has taken place. Revenue as reported, represents the Company's share and is presented before royalty payments to governments and other mineral interest owners. Other revenue is recognized in the period that the service is provided to the customer.

J) STOCK-BASED COMPENSATION PLAN

The Company records compensation expense in the consolidated statements of earnings and other comprehensive income for stock options granted to directors, officers, and employees using the fair-value method. Compensation costs are recognized over the vesting period and the fair values are determined using the Black-Scholes option pricing model.

Contributions to the Company's stock savings plan are recorded as compensation expense as incurred.

K) DEFERRED FINANCING CHARGES

On January 1, 2007 financing costs related to the issuance of senior term notes were reclassified from other assets to senior term notes, as disclosed in Note 2. The costs capitalized within long term debt are amortized using the effective interest method.

L) FOREIGN CURRENCY TRANSLATION

Monetary assets and liabilities of the Company that are denominated in foreign currencies are translated into Canadian dollars at the period-end exchange rate, with any resulting gain or loss recorded in the consolidated statement of earnings and other comprehensive income.

M) DIVIDEND POLICY

The Company has neither declared nor paid any dividends on its common shares. The Company intends to retain its earnings to finance growth and expand its operations and does not anticipate paying any dividends on its common shares in the foreseeable future.

N) DEFINED BENEFIT PENSION PLAN

The Company accrues for obligations under a defined benefit pension plan and the related costs, net of plan assets for employees of Mazeppa Processing Partnership. The cost of the pension is actuarially determined using the projected benefit method based on length of service and reflects Management's best estimate of expected plan investment performance, salary escalation, and retirement age of employees.

Notes to the Consolidated Financial Statements

O) RECENT ACCOUNTING PRONOUNCEMENTS

On January 1, 2008, the Company will be required to adopt the following CICA Handbook Sections:

- Section 3031, *"Inventories"* which replaces the existing standard. The requirements include the consistent grouping of like assets and the application of the first-in-first-out or weighted average cost formula methodologies.
- Section 1400, *"General Standards of Financial Statement Presentation"* which requires assessing and disclosing the Company's ability to continue as a going concern.
- Section 3862, *"Financial Instruments – Disclosures"* and Section 3863, *"Financial Instruments – Presentation"*. These new standards will require increased disclosure of financial instruments with particular emphasis on the risks associated with recognized and unrecognized financial instruments and how those risks are managed.
- Section 1535, *"Capital Disclosures"*, requiring disclosure of information about an entity's capital and the objectives, policies, and processes for managing capital.

The adoption of these standards is not expected to have a material impact on the Company's consolidated financial statements.

On January 1, 2009 the Company will be required to adopt the CICA Handbook Section 3064, *"Intangible Assets"*. The new section establishes standards for the recognition, measurement, and disclosure of goodwill and intangible assets and replaces the existing Handbook Section 3062, *"Goodwill and Other Intangible Assets"* and Section 3450, *"Research and Development Costs"*. Intangible assets associated with the exploration and development of oil and gas assets are specifically excluded under the new standard. The Company is evaluating the implications but expects no material impact on the consolidated financial statements.

On January 10, 2006, the CICA Accounting Standards Board ("AcSB") ratified a new strategic plan that would see the convergence of Canadian Generally Accepted Accounting Principles ("GAAP") with International Financial Reporting Standards ("IFRS") within 5 years. In March 2007, the AcSB released an *"Implementation Plan for Incorporating IFRSs into Canadian GAAP"*, which assumed a convergence date of January 1, 2011. The AcSB confirmed this date in February 2008. The Company continues to monitor and assess the consequences of the convergence on the consolidated financial statements as they could have a material impact.

P) RECLASSIFICATION

Certain amounts disclosed for prior years have been reclassified to conform with current year presentation.

2. CHANGES IN SIGNIFICANT ACCOUNTING POLICIES

On January 1, 2007, the Company adopted the CICA Handbook Section 1530, *"Comprehensive Income"*, Handbook Section 3855, *"Financial Instruments – Recognition and Measurement"* Handbook Section 3861, *"Financial Instruments – Disclosure and Presentation"*, Handbook Section 3865, *"Hedges"*, and Handbook Section 1506, *"Accounting Changes"*.

The adoption of these standards had no material impact on the Company's consolidated financial statements. Any significant effects from the implementation of the new standards are disclosed below.

A) COMPREHENSIVE INCOME

The new standard introduced the statements of comprehensive income and accumulated other comprehensive income to temporarily provide for gains, losses and other amounts arising from changes in fair value until realized and recorded in net earnings. The Company has determined that it has no other comprehensive income nor accumulated other comprehensive income for the year ended December 31, 2007.

B) FINANCIAL INSTRUMENTS

The financial instruments standard establishes recognition and measurement criteria for financial assets, financial liabilities and derivatives. The Company's policies on accounting for financial instruments is disclosed in Note 1.

Transitional provisions were outlined in the financial instruments standard and required retroactive adjustment without restatement of prior periods. In addition, the provisions required that, upon adoption at January 1, 2007, transitional adjustments, net of tax, be recognized in the opening balance of retained earnings.

At January 1, 2007, the following transitional adjustments were required.

- The reclassification of $14.0 million of deferred financing charges as a reduction of senior term notes to reflect the adopted policy of netting long term debt transaction costs within long term debt. The costs capitalized will be amortized using the effective interest method. Previously, the Company deferred these costs and amortized them straight line over the life of the related senior term notes. The adoption of this standard resulted in a $0.3 million net increase to opening retained earnings.
- $3.97 million of deferred risk management loss, $2.7 million net of tax, previously recognized at January 1, 2004 upon initial adoption of CICA Accounting Guideline 13, *"Hedging Relationships"* was reclassified as a reduction to opening retained earnings.
- The fair value measurement of investments resulted in a $1.1 million net increase to opening retained earnings.

The net effect on opening retained earnings as a result of the transitional provisions is as follows:

Deferred financing charge adjustments	$	318
Deferred risk management loss		(2,743)
Fair value of investments		1,105
Total adjustment to opening retained earnings	$	(1,320)

3. Business combinations

On August 15, 2007 and December 21, 2007, respectively, the Company acquired all of the issued and outstanding shares of Stylus Energy Inc. ("Stylus") and WIN Energy Corporation ("WIN"). Both entities were independent exploration and production companies with operations in the Company's core areas. The business combinations have been accounted for using the purchase method with results of operations included in the consolidated financial statements from the date of acquisition. If the purchase price is in excess of the fair value of net assets acquired, goodwill is recorded.

Notes to the Consolidated Financial Statements

The following table summarizes the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition. The Company is in the process of finalizing the estimated fair value of the WIN acquisition and therefore, the allocation of the purchase price is subject to refinement.

Net assets acquired	Stylus	WIN	Total
Working capital	$ (17,209)	$ (2,010)	$ (19,219)
Petroleum and natural gas properties	106,916	24,465	131,381
	89,707	22,455	112,162
Future income taxes	(12,288)	8,132	(4,156)
Asset retirement obligations	(4,402)	(919)	(5,321)
Goodwill	2,020	–	2,020
	$ 75,037	$ 29,668	$ 104,705
Consideration			
Cash	$ 73,782	$ 29,414	$ 103,196
Transaction costs	1,255	254	1,509
	$ 75,037	$ 29,668	$ 104,705

During the year ended December 31, 2007, both companies were wound up into Compton Petroleum Corporation.

4. Non-controlling interest

Mazeppa Processing Partnership ("MPP" or "the Partnership") is a limited partnership organized under the laws of the province of Alberta and owns certain midstream facilities, including gas plants and pipelines in Southern Alberta. The Company processes a significant portion of its production from the area through these facilities pursuant to a processing agreement with MPP. The Company does not have an ownership position in MPP, however, the Company, through a management agreement, manages the activities of MPP and is considered to be the primary beneficiary of MPP's operations. Pursuant to AcG-15, these consolidated financial statements include the assets, liabilities, and operations of the Partnership. Equity in the Partnership, attributable to the partners of MPP, is recorded on consolidation as a non-controlling interest and is comprised of the following:

As at December 31,	**2007**	2006
Non-controlling interest, beginning of year	**$ 66,350**	$ 68,898
Earnings attributable to non-controlling interest	**6,132**	6,623
Distributions to limited partner	**(9,171)**	(9,171)
Non-controlling interest, end of year	**$ 63,311**	$ 66,350

Commencing May 1, 2004, pursuant to the terms of a processing agreement between Compton and MPP, Compton pays a monthly fee to MPP for the transportation and processing of natural gas through the MPP owned facilities. The fee is comprised of a fixed base fee of $764 thousand per month plus MPP operating costs, net of third party revenues. These amounts are eliminated from revenues and expenses on consolidation.

The processing agreement has a five year term ending April 1, 2009, at which time Compton may renew the agreement under terms determined at that time or purchase the Partnership units for the predetermined amount of $55 million, deemed to be fair value. In the event that the Company does not renew the processing agreement nor exercise the purchase option, the limited partner may dispose of the Partnership units to an independent third party.

MPP has guaranteed payment of certain obligations of its limited partner under a credit agreement between the limited partner and a syndicate of lenders. The maximum liability of the Partnership under the guarantee is limited to amounts due and payable to MPP by the Company pursuant to the processing agreement. The maximum liability at December 31, 2007 was $12.2 million (2006 - $21.4 million) payable over the remaining term of the processing agreement. The Company has determined that its exposure to loss under these arrangements is negligible.

5. Property and equipment

As at December 31, 2007	**Cost**	**Accumulated depletion and depreciation**	**Net**
Exploration and development costs	**$ 2,145,866**	**$ (603,867)**	**$1,541,999**
Production equipment and processing facilities	**651,999**	**(105,720)**	**546,279**
Inventory	**6,871**	**–**	**6,871**
Future asset retirement costs	**19,940**	**(5,396)**	**14,544**
Office equipment	**14,111**	**(6,970)**	**7,141**
	$ 2,838,787	**$ (721,953)**	**$2,116,834**

As at December 31, 2006	Cost	Accumulated depletion and depreciation	Net
Exploration and development costs	$ 1,931,594	$ (482,524)	$ 1,449,070
Production equipment and processing facilities	582,705	(77,863)	504,842
Inventory	6,818	–	6,818
Future asset retirement costs	17,128	(4,906)	12,222
Office equipment	9,359	(5,249)	4,110
	$ 2,547,604	$ (570,542)	$ 1,977,062

During the year, $9.6 million (2006 - $10.5 million) relating to employee salaries, insurance costs, and overhead recoveries determined in accordance with industry standards, were capitalized.

As at December 31, 2007, future capital expenditures of $318.3 million (2006 - $329.7 million, 2005 - $192.9 million), as estimated by independent reserve engineers, relating to the development of proved reserves have been included in costs subject to depletion. The estimated salvage value of production equipment and processing facilities at December 31, 2007 was $130.1 million (2006 - $120.1 million, 2005 - $108.6 million) and was excluded from costs subject to depletion. Undeveloped properties with a cost at December 31, 2007 of $260.6 million (2006 - $202.9 million, 2005 - $251.3 million) included in exploration and development costs, have not been subject to depletion.

Prices used in the evaluation of the carrying value of the Company's reserves for the purposes of the impairment test are:

As at December 31, 2007	**Natural Gas** (AECO C spot) $ per mmbtu	**Crude Oil** (Edmonton par 40° API) $ per bbl	**NGL** $ per bbl
2008	$ 6.74	$ 88.48	$ 91.04
2009	$ 7.48	$ 85.52	$ 88.03
2010	$ 7.69	$ 83.88	$ 86.41
2011	$ 7.80	$ 82.03	$ 84.54
2012	$ 7.84	$ 81.16	$ 83.66
Approximate % increase thereafter	2.0%	2.0%	2.0%

Notes to the Consolidated Financial Statements

6. Credit facilities

As at December 31,	2007	2006
Authorized	$ 500,000	$ 500,000
Prime rate	$ 50,000	$ 35,000
Bankers' Acceptance	350,000	295,000
Discount to maturity	(1,574)	(2,000)
Utilized	$ 398,426	$ 328,000

As at December 31, 2007, the Company had arranged a $500 million authorized senior credit facility with a syndicate of banks. Advances under the facilities can be drawn and currently bear interest as follows:

Prime rate plus 0.95%
Bankers' Acceptance rate plus 1.95%
LIBOR rate plus 1.95%

At December 31, 2007 prime and 30 day bankers acceptance rates were 6.0% and 4.6% respectively.

Margins are determined based on the ratio of total consolidated debt to consolidated cash flow. The facilities reached term on July 4, 2007 and were renewed under the same terms and conditions to July 2, 2008. If not renewed in 2008 they will mature 366 days later on July 3, 2009.

The senior credit facilities are secured by a first fixed and floating charge debenture in the amount of $1.0 billion covering all the Company's assets and undertakings.

7. Senior term notes

As at December 31,	2007	2006
Senior term notes		
US$450 million, 7.625% due December 1, 2013	**$ 444,645**	$ 524,385
Unamortized transaction costs	**(10,883)**	–
Carrying value	**$ 433,762**	$ 524,385

On November 22, 2005, a wholly owned subsidiary of the Company issued US$300 million senior term notes maturing December 1, 2013. On April 4, 2006, an additional US$150 million was issued under the same terms and conditions as the original issue. The notes bear interest at 7.625%, are unsecured and are subordinate to the Company's bank credit facilities. The yield to maturity, using the effective interest method, was 8.840% as at December 31, 2007.

Pursuant to the adoption of Handbook Section 3855, *"Financial Instruments – Recognition and Measurement"*, transaction costs relating to the issue of the senior term notes reduce the carrying value of the notes as disclosed in Note 2.

The notes are not redeemable by the Company prior to December 1, 2009, except in limited circumstances. After that time, they can be redeemed in whole or part, at the rates indicated below:

December 1, 2009	103.813%
December 1, 2010	101.906%
December 1, 2011 and thereafter	100.000%

During the year the Company entered into foreign exchange contracts as outlined in Note 17(a)(iii) which fixed the repayment, in Canadian dollars, December 1, 2010 being the second call date as outlined in the senior note agreement.

8. Interest and finance charges

Amounts charged to expense during the year ended are as follows:

Years ended December 31,	2007	2006	2005
Interest on bank debt, net	$ 22,476	$ 14,243	$ 11,520
Interest on senior term notes	38,345	35,880	20,912
Other finance charges	2,672	3,952	2,519
Total	$ 63,493	$ 54,075	$ 34,951

Other finance charges include lease financing, bank service charges and fees as well as other miscellaneous expenses.

The effective interest rate on bank debt at December 31, 2007 was 6.5% (2006 - 5.6%).

9. Other assets

As at December 31,	2007	2006
Deferred financing charges	$ –	$ 14,008
Defined benefit pension plan	277	125
Other	14	11
Other assets	$ 291	$ 14,144

On January 1, 2007 financing costs related to the issuance of senior term notes were reclassified from other assets to senior term notes, as disclosed in Note 2.

10. Foreign exchange (gain) loss

Amounts charged to foreign exchange (gain) loss during the year ended were as follows:

Years ended December 31,	2007	2006	2005
Foreign exchange gain on translation of US$ debt	$ (79,740)	$ (665)	$ (7,808)
Other foreign exchange (gain) loss	1,023	(226)	455
Total	$ (78,717)	$ (891)	$ (7,353)

11. Asset retirement obligations

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the obligations associated with the retirement of oil and natural gas assets:

As at December 31,	2007	2006
Asset retirement obligations, beginning of year	$ 29,791	$ 20,770
Liabilities incurred	8,719	7,031
Liabilities settled and disposed	(4,532)	(267)
Accretion expense	2,718	2,257
Asset retirement obligations, end of year	$ 36,696	$ 29,791

The total undiscounted amount of estimated cash flows required to settle the obligations was $246.6 million (2006 - $233.0 million), which has been discounted using a credit-adjusted risk free rate of 10.8% (2006 – 10.6%). Due to the Company's long reserve life, the majority of these obligations are not expected to be settled until well into the future. Settlements will be funded from general Company resources at the time of retirement and removal.

Notes to the Consolidated Financial Statements

12. Capital stock

A) AUTHORIZED

The Company is authorized to issue an unlimited number of common shares and an unlimited number of preferred shares, issuable in series.

B) ISSUED AND OUTSTANDING

	2007		2006	
[illegible] December 31,	**Number of Shares (000s)**	**Amount**	Number of Shares (000s)	Amount
Common shares outstanding, beginning of year	**128,503**	**$ 231,992**	127,263	$ 226,444
Shares issued under stock option plan	**993**	**4,603**	1,489	5,993
Shares repurchased	**(398)**	**(724)**	(249)	(445)
Common shares outstanding, end of year	**129,098**	**$ 235,871**	128,503	$ 231,992

The Company, has, on an annual basis, instituted a normal course issuer bid program. Under the current program, the Company may purchase for cancellation up to 6,000,000 of its common shares, representing approximately 5.0% of the issued and outstanding common shares at the time the bid received regulatory approval.

During the year, the Company purchased for cancellation 398,300 common shares at an average price of $9.98 per share (2006 – 248,900 common shares at an average price of $13.79 per share) pursuant to the normal course issuer bid. The excess of the purchase price over book value has been charged to retained earnings.

C) SHAREHOLDER RIGHTS PLAN

The Company has a shareholder rights plan (the "Plan") to ensure all shareholders are treated fairly in the event of a take-over offer or other acquisition of control of the Company.

Pursuant to the Plan, the Board of Directors authorized and declared the distribution of one Right in respect of each common share outstanding. In the event that an acquisition of 20% or more of the Company's shares is completed and the acquisition is not a permitted bid, as defined by the Plan, each Right will permit the holder, other than holders not in compliance with the plan, to acquire a common share at a 50% discount to the market price at that time.

13. Stock-based compensation plans

A) STOCK OPTION PLAN

The Company has a stock option plan for employees, including directors and officers. The exercise price of each option approximated the market price for the common shares on the date the option was granted. Options granted under the plan before June 1, 2003 are fully exercisable and will expire ten years after the grant date. Options granted under the plan after June 1, 2003 are generally fully exercisable after four years and expire five years after the grant date.

The following tables summarize the information relating to stock options:

As at December 31,	**2007** Stock options (000s)		2007 Weighted average exercise price	2006 Stock Options (000s)		2006 Weighted average exercise price
Outstanding, beginning of year	**11,611**	$	**7.79**	11,446	$	6.13
Granted	**2,074**	$	**11.02**	2,228	$	13.99
Exercised	**(993)**	$	**3.47**	(1,489)	$	3.14
Forfeited	**(608)**	$	**11.97**	(574)	$	10.92
Outstanding, end of year	**12,084**	$	**8.49**	11,611	$	7.79
Exercisable, end of year	**7,240**	$	**6.20**	6,593	$	4.82

The range of exercise prices of stock options outstanding and exercisable at December 31, 2007 is as follows:

Range of exercise prices	Outstanding Options: Number of options outstanding (000s)	Outstanding Options: Weighted average remaining contractual life (years)		Outstanding Options: Weighted average exercise price	Exercisable Options: Number of options outstanding (000s)		Exercisable Options: Weighted average exercise price
$1.45 - $3.99	2,665	2.6	$	2.72	2,665	$	2.72
$4.00 - $6.99	2,013	2.7	$	4.94	1,995	$	4.93
$7.00 - $9.99	1,533	2.2	$	7.94	884	$	7.63
$10.00 - $11.99	2,740	3.4	$	11.19	633	$	10.92
$12.00 - $13.99	1,713	2.7	$	12.63	698	$	12.61
$14.00 - $18.39	1,420	3.1	$	14.69	365	$	14.70
	12,084	2.9	$	8.49	7,240	$	6.20

The Company has recorded stock-based compensation expense in the consolidated statement of earnings and other comprehensive income for stock options granted to employees, directors, and officers after January 1, 2003 using the fair value method.

Notes to the Consolidated Financial Statements

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted average assumptions for grants as follows:

Years ended December 31,	2007	2006	2005
Weighted average fair value of options granted	$ **4.23**	$ 6.90	$ 5.45
Risk-free interest rate	**4.1%**	4.0%	3.6%
Expected life (years)	**5.0**	5.0	5.0
Expected volatility	**39.0%**	43.5%	43.9%

The following table presents the reconciliation of contributed surplus with respect to stock-based compensation:

As at December 31,	2007	2006
Contributed surplus, beginning of year	$ **16,974**	$ 9,173
Stock-based compensation expense	**8,416**	9,121
Stock options exercised	**(1,157)**	(1,320)
Contributed surplus, end of year	$ **24,233**	$ 16,974

B) SHARE APPRECIATION RIGHTS PLAN

CICA Handbook section 3870 requires recognition of compensation costs with respect to changes in the intrinsic value for the variable component of fixed share appreciation rights ("SARs"). During the years ended December 31, 2007, 2006 and 2005, there were no significant compensation costs related to the outstanding variable component of these SARs. The liability related to the variable component of these SARs amounts to $1.0 million, which is included in accounts payable as at December 31, 2007 (2006 - $1.2 million). All outstanding SARs having a variable component expire at various times through 2011.

C) EMPLOYEE RETENTION PROGRAM

In recognition of the shortage of qualified personnel that existed within the industry, the Company implemented an Employee Retention program in July 2006 for its existing employees at the time, excluding officers and directors. Under the program, the Company incurred additional compensation costs of $4.0 million, in July 2007, $2.6 million of which was recognized in 2007 and the balance in 2006. Amounts paid under the program were determined in relation to the market value of the Company's capital stock and accordingly have been included in stock-based compensation. No further obligation exists pursuant to this program.

14. PER SHARE AMOUNTS

The following table summarizes the common shares used in calculating net earnings per common share:

Years ended December 31, (000s)	2007	2006	2005
Weighted average common shares outstanding – basic	**128,993**	127,820	125,627
Effect of stock options	**3,546**	5,806	6,040
Weighted average common shares outstanding – diluted	**132,539**	133,626	131,667

In calculating diluted earnings per common share for the year ended December 31, 2007, the Company excluded 5,553,700 options (2006 – 1,537,100, 2005 – 331,800) as the exercise price was greater than the average market price of its common shares in those years.

15. Defined benefit pension plan

There are 35 employees of MPP currently enrolled in a co-sponsored, defined benefit pension plan. Information relating to the MPP retirement plan is outlined below:

As at December 31,	2007	2006
Accrued benefit obligation		
Accrued benefit obligation – beginning of year	$ 7,717	$ 7,562
Current service cost	401	368
Interest cost	403	387
Benefits paid	(121)	(392)
Actuarial (gain) loss	(705)	(208)
Accrued benefit obligation – end of year	$ 7,695	$ 7,717
Fair value of plan assets		
Fair value of plan assets – beginning of year	$ 6,635	$ 5,839
Employee contributions	87	82
Employer contributions	460	439
Benefits paid	(121)	(392)
Actual return on plan assets	(164)	667
Fair value of plan assets – end of year	$ 6,897	$ 6,635
Accrued benefit asset		
Funded status – plan assets less than benefit obligation	$ (798)	$ (1,082)
Unamortized net actuarial loss	352	414
Unamortized past service costs	723	793
Accrued benefit asset, included in other assets (Note 9)	$ 277	$ 125

Economic assumptions used to determine benefit obligation and periodic expense were:

Years ended December 31,	2007	2006
Discount rate	5.0%	5.0%
Expected rate of return on assets	7.0%	7.0%
Rate of compensation increase	3.5%	3.5%
Average remaining service period of covered employees	16 years	16 years

Actuarial evaluations are required every three years, the next evaluation being January 1, 2009.

Pension expense, included in MPP operating costs, is as follows:

Years ended December 31,	2007	2006
Current service cost, net of employee contributions	$ 307	$ 292
Interest on accrued benefit obligation	403	387
Return on assets	(479)	(407)
Amortization of past service cost	69	69
Amortization of net actuarial loss	–	9
Pension expense, included in operating expense	$ 300	$ 350

MPP expects to contribute $547 thousand to the plan in 2008.

Notes to the Consolidated Financial Statements

16. Income taxes

A) The following table reconciles income taxes calculated at the Canadian statutory rate with actual income taxes:

Years ended December 31,	**2007**	2006	2005
Earnings before taxes and non-controlling interest	**$ 108,963**	$ 130,457	$ 145,247
Canadian statutory rate	**32.1%**	34.5%	37.6%
Expected income taxes	**$ 34,977**	$ 45,008	$ 54,613
Effect on taxes resulting from:			
Non-deductible Crown charges	**–**	2,145	15,061
Resource allowance	**–**	(1,987)	(11,980)
Non-deductible stock-based compensation	**2,704**	3,147	2,221
Federal capital tax	**–**	–	1,896
Effect of tax rate changes	**(50,470)**	(49,655)	(5,764)
Non-taxable capital (gains) losses	**(11,651)**	(115)	–
Other	**(1,995)**	(2,135)	1,341
Provision for income taxes	**$ (26,435)**	$ (3,592)	$ 57,388
Current			
Income taxes	**$ 17**	$ 44	$ 3,175
Federal capital taxes	**–**	–	1,896
Future	**(26,452)**	(3,636)	52,317
	$ (26,435)	$ (3,592)	$ 57,388
Effective tax rate	**(24.3)%**	(2.8)%	39.5%

A significant portion of the Company's taxable income is generated by a partnership. Income taxes are incurred on the majority of the partnership's taxable income in the year following its inclusion in the Company's consolidated net earnings. Current income tax is dependent upon the amount of capital expenditures incurred and the method of deployment.

The Canadian federal government, during the fourth and second quarters of 2007 and the second quarter of 2006, and the Alberta government, during the second quarter of 2006 enacted income tax rate changes.

B) Future income taxes are classified on the balance sheet as:

As at December 31,	**2007**	2006
Current asset	**$ (2,606)**	$ (1,479)
Current liability	**542**	7,269
Non-current liability	**293,494**	302,690
Net future income tax liability	**$ 291,430**	$ 308,480

The net future income tax liability is comprised of:

As at December 31,	**2007**	2006
Future income tax liabilities		
Property and equipment in excess of tax values	**$ 252,594**	$ 229,936
Timing of partnership items	**43,857**	83,328
Foreign exchange gain on long-term debt	**18,340**	8,729
Other	**–**	2,591
Future income tax assets		
Non-capital losses carried forward	**(5,422)**	-
Attributed Canadian royalty income	**(7,810)**	(7,462)
Asset retirement obligations	**(9,177)**	(8,642)
Other	**(952)**	-
Net future income tax liability	**$ 291,430**	$ 308,480

The non-capital losses available for carry forward to reduce taxable income in future years expire between 2011 and 2026.

17. Financial instruments

DERIVATIVE FINANCIAL INSTRUMENTS AND RISK MANAGEMENT ACTIVITIES

The Company is exposed to risks from fluctuations in commodity prices, interest rates, and Canada/US currency exchange rates. The Company utilizes various derivative financial instruments for non-trading purposes to manage and mitigate its exposure to these risks. Effective January 1, 2004, the Company elected to account for all derivative financial instruments using the mark-to-market method.

On January 1, 2007 the Company adopted the new financial instrument recognition, measurement, presentation and disclosure requirements of the CICA as disclosed in Note 2 (b) to these consolidated financial statements. Certain items have been reclassified as a reduction to opening retained earnings, net of tax, as prescribed in the transitional provisions.

Risk management activities during the year, utilizing derivative instruments, relate to commodity price economic hedges, a fixed price power contract, foreign currency contracts and cross currency interest rate swap arrangements.

A) UNREALIZED RISK MANAGEMENT GAINS AND LOSSES AS AT DECEMBER 31, 2007

I) BALANCE SHEET CLASSIFICATION

As at December 31, 2007, the Company had outstanding financial instrument contracts for both commodity price risk management and foreign currency risk management expiring at various periods to December 2010. These contracts were valued on a mark-to-market basis as at December 31, 2007 and the unrealized gains and losses relating to these contracts are recorded on the consolidated balance sheets as follows:

As at December 31, 2007	Commodity Contracts	Foreign Currency	**2007 Total**	2006 Total
Unrealized gain				
Current asset	$ 1,790	$ 45	**$ 1,835**	$ 22,625
Non-current asset	–	14,320	**14,320**	–
Unrealized loss				
Current liability	–	(8,832)	**(8,832)**	(4,604)
Non current liability	–	(1,585)	**(1,585)**	(6,816)
Total unrealized gains (losses)	$ 1,790	$ 3,948	**$ 5,738**	$ 11,205

Notes to the Consolidated Financial Statements

The amounts relating to commodity price risk management and foreign exchange risk management, respectively, are disclosed below.

II) COMMODITY PRICE RISK MANAGEMENT

The Company enters into economic hedge transactions relating to crude oil and natural gas prices to mitigate volatility in commodity prices and the resulting impact on cash flow. The contracts entered into are forward transactions providing the Company with a range of prices on the commodities sold. Prices are marked to industry benchmarks specifically AECO spot for gas contracts and WTI NYMEX for oil contracts and are valued in Canadian dollars unless otherwise disclosed. Outstanding economic hedge contracts at December 31, 2007 are:

Commodity	Term	Daily Notional Volume	Average Price	Mark-to-Market gain
Natural gas collar	Nov./07 - Mar./08	9,524mcf	\$8.27 - \$10.50/mcf	\$ 1,416
Electricity	Jan./06 - Dec./08	2.5 MW	\$55.00/MWh	374
				\$ 1,790

The gains and losses realized during the year on the electricity contract are included in operating expenses.

Subsequent to December 31, 2007, the Company entered into the following commodity contracts:

Commodity	Term	Daily Notional Volume	Average Price
Natural gas			
Collar	Apr./08 – Oct./08	52,381 mcf	\$7.33 - \$8.48/mcf
Fixed	Apr./08 – Oct./08	19,048 mcf	\$7.86/mcf
Collar	Nov./08 – Mar./09	28,571 mcf	\$8.40 - \$10.00/mcf
Fixed	Nov./08 – Mar./09	9,524 mcf	\$8.51/mcf
Oil			
Fixed	Mar./08 – Dec./08	1,000 bbl	US\$93.00/bbl

III) FOREIGN CURRENCY RISK MANAGEMENT

The Company is exposed to fluctuations in the exchange rate between the Canadian dollar and the US dollar. Crude oil and to a certain extent natural gas prices are based upon reference prices denominated in US dollars, while the majority of the Company's expenses are denominated in Canadian dollars. When appropriate, the Company enters into agreements to fix the exchange rate of Canadian dollars to US dollars in order to manage the risk.

Concurrent with the issuance of 9.90% Senior Notes in 2002, the Company entered into cross currency interest rate swap arrangements expiring May 2009 that convert fixed rate US dollar denominated interest obligations into floating rate Canadian dollar denominated interest obligations. On purchase of the majority of the 9.90% Senior Notes in November 2005, the Company elected not to collapse the cross currency interest rate swap and maintains it as a source of US funds used to settle interest obligations on the 7.625% Senior Notes.

During the year the Company entered into a series of foreign exchange contracts relating to the US\$450 million senior notes due December 1, 2013, effectively fixing the liability in Canadian dollars on December 1, 2010, being the second call date of the senior notes. Additionally, the Company entered into a series of foreign exchange contracts relating to the semi-annual interest settlement obligations until November 30, 2010.

On December 31, 2007 the Company had the following foreign exchange contracts in place:

Contract	Amount USD	Rate	Amount CDN	Term	Mark to Market
Currency swap	$450,000,000	96.9750	$436,387,500	Matures on December 1, 2010	$ 14,146
Currency swap	$78,435,000	99.5500	$78,082,043	Equal payments on May 30 and Nov. 30 until 2010	219
Cross currency interest rate swap	$24,502,500	BA plus 4.845%	$34,627,785	Equal payments on May 15 and Nov. 15 until 2009	(10,417)
Total unrealized foreign exchange gain (loss)					$ 3,948

B) RISK MANAGEMENT (GAIN) LOSS

Risk management gains and losses recognized in the consolidated statements of earnings and other comprehensive income during the periods relating to commodity prices and foreign currency transactions are summarized below:

Year ended December 31, 2007	**Commodity Contracts**	**Foreign Currency**	**Total**
Unrealized			
Change in fair value	**$ 20,834**	**$ (15,367)**	**$ 5,467**
Realized cash settlements	**(19,220)**	**7,739**	**(11,481)**
Total (gain) loss	**$ 1,614**	**$ (7,628)**	**$ (6,014)**

Year ended December 31, 2006	Commodity Contracts	Foreign Currency	Total
Unrealized			
Amortization of deferred loss	$ –	$ 1,642	$ 1,642
Change in fair value	(25,775)	(3,389)	(29,164)
	(25,775)	(1,747)	(27,522)
Realized cash settlements	(39,217)	3,018	(36,199)
Total (gain) loss	$ (64,992)	$ 1,271	$ (63,721)

Year ended December 31, 2005	Commodity Contracts	Foreign Currency	Total
Unrealized			
Amortization of deferred loss	$ –	$ 1,642	$ 1,642
Change in fair value	5,136	3,393	8,529
	5,136	5,035	10,171
Realized cash settlements	9,663	(532)	9,131
Total loss	$ 14,799	$ 4,503	$ 19,302

C) CREDIT RISK MANAGEMENT

Accounts receivable include amounts receivable for oil and natural gas sales which are generally made to large credit worthy purchasers and amounts receivable from joint venture partners which are generally recoverable from production. Accordingly, the Company views credit risks on these amounts as low.

The Company is exposed to losses in the event of non-performance by counter-parties to financial instruments. The Company deals with major financial institutions and believes these risks are minimal.

Notes to the Consolidated Financial Statements

D) FAIR VALUE OF FINANCIAL ASSETS AND LIABILITIES

Held for trading financial assets and liabilities are carried at fair value. The carrying value of accounts receivable, accounts payable, and bank debt approximate fair value due to the short term nature of these instruments and variable rates of interest. The senior term notes trade in the U.S. and the estimated fair value was determined using quoted market prices.

	2007		2006	
As at December 31,	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Financial Assets				
Held-for-trading				
Cash	**$ 8,665**	**$ 8,665**	$ 11,876	$ 11,876
Other current assets	**19,772**	**19,772**	22,869	22,869
Loans and receivables				
Accounts receivable	**$ 80,331**	**$ 80,331**	$ 83,535	$ 83,535
Financial Liabilities				
Other financial liabilities				
Accounts payable	**$ 147,983**	**$ 147,983**	$ 141,443	$ 141,443
Bank debt	**398,426**	**398,426**	328,000	328,000
Senior term notes	**433,762**	**415,743**	524,385	503,410

The fair value of derivative financial instruments related to risk management activities, classified as held-for-trading, are disclosed elsewhere in this note.

18. Cash flow

Changes in non-cash working capital items increased (decreased) cash as follows:

Years ended December 31,	**2007**	2006	2005
Accounts receivable and other current assets	**$ (11,614)**	$ 24,395	$ (17,672)
Accounts payable	**6,540**	(62,425)	78,385
	$ (5,074)	$ (38,030)	$ 60,713
Net change in non-cash working capital			
Relating to:			
Operating activities	**$ (23,366)**	$ 19,823	$ 6,612
Investing activities	**18,292**	(57,853)	54,101
	$ (5,074)	$ (38,030)	$ 60,713

Amounts paid during the year relating to interest expense and capital taxes were as follows:

Years ended December 31,	**2007**	2006	2005
Interest paid	**$ 60,976**	$ 48,857	$ 31,444
Current income taxes paid	**$ 41**	$ 14	$ 4,101

19. Commitments and contingent liabilities

A) COMMITMENTS

The Company has committed to certain payments over the next five years, as follows:

	2008	2009	2010	2011	2012
Operating leases	$ 3,811	$ 3,325	$ 505	$ –	$ –
Office facilities	4,351	4,921	6,160	5,484	5,569
MPP partnership distributions	9,172	3,057	–	–	–
	$ 17,334	$ 11,303	$ 6,665	$ 5,484	$ 5,569

The Company has entered into a lease agreement for new office facilities commencing 2009. Annual commitments under the lease agreement are approximately $5.6 million per year for the 10 year term. The commitment remaining on the office facilities subsequent to 2012 is $33.6 million and the total of all commitments to expiry is $80 million.

B) LEGAL PROCEEDINGS

The Company is involved in various legal claims associated with normal operations. These claims, although unresolved at the current time, in management's opinion, are not significant and are not expected to have a material impact on the financial position or results of operations of the Company.

20. Subsequent events

On January 23, 2008, Compton announced its budget for 2008 and the Company's longer term plans for 2009 and 2010. On January 29, 2008, the Company received a letter from Centennial Energy Partners LLC, a major shareholder of the Company, wherein they restated comments contained in a letter to the Company dated December 14, 2007, that in their opinion, a major discount had developed between the underlying value of the Company's asset base and its share price. Additionally, they expressed concerns that the Company's plans, as announced, would not eliminate the discount and require Compton shareholders' to assume significant execution risk, commodity price risk and stock market risk for minimal per-share return and requested that the Company be put up for sale.

In response to Centennial's concerns, the Board of Directors, in a news release dated February 28, 2008, announced that it would conduct a formal review of the Company's business plans and alternatives for enhancing shareholder value, and had appointed independent financial advisors to assist the Company in the conduct of this review.

The Company has estimated that during 2008, Compton will incur direct costs associated with, and costs resulting from, the process that could total approximately $22 million. These expenses will be recognized throughout the year as they occur.

In addition to the above, cash outlays associated with change of control provisions relating to the Company's senior notes, Mazeppa Processing Partnership arrangements, and employee contracts could result depending upon the outcome of the review.

21. United States accounting principles and reporting

Reconciliation of consolidated financial statements to United States generally accepted accounting principles

These consolidated financial statements have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP") which, in most respects, conforms to accounting principles generally accepted in the United States of America ("US GAAP"). The significant differences in those principles, as they apply to the Company's statements of earnings and other comprehensive income, balance sheets, and statements of cash flows, are described below.

Notes to the Consolidated Financial Statements

RECONCILIATION OF NET EARNINGS UNDER CANADIAN GAAP TO US GAAP:

For the years ended December 31,	**2007**	2006	2005
Net earnings for year, as reported	$ **129,266**	$ 127,426	$ 81,326
Adjustments			
Depletion and depreciation, net (Note a)	**(625)**	(7,744)	650
Risk management gain, net (Note c)	**–**	1,166	1,067
Business combination, net (Note g)	**(201)**	–	–
Net earnings – US GAAP	$ **128,440**	$ 120,848	$ 83,043

CONSOLIDATED STATEMENTS OF EARNINGS – US GAAP

For the years ended December 31,	**2007**	2006	2005
Revenue, net of royalties	$ **398,309**	$ 417,160	$ 431,524
Expenses			
Operating	**101,478**	102,643	73,164
Transportation	**12,615**	12,564	10,858
General and administrative	**31,328**	26,231	21,223
Interest and finance charges	**63,493**	54,075	55,701
Depletion and depreciation (Note a)	**152,244**	153,964	104,525
Foreign exchange gain	**(78,717)**	(891)	(7,353)
Accretion of asset retirement obligations	**2,718**	2,257	1,975
Stock-based compensation	**11,034**	10,488	5,903
Guarantee (Note f)	**–**	(375)	(375)
Loss on equity investment (Note g)	**159**	–	–
Risk management (gain) loss (Note c)	**(6,014)**	(65,363)	17,660
Earnings before taxes and non-controlling interest	**107,971**	121,567	148,243
Income tax (recovery) expense (Note a, g)	**(26,602)**	(6,279)	58,292
Non-controlling interest (Note f)	**6,133**	6,998	6,908
Net earnings – US GAAP	$ **128,440**	$ 120,848	$ 83,043
Net earnings per common share – US GAAP			
Basic	$ **1.00**	$ 0.95	$ 0.66
Diluted	$ **0.97**	$ 0.90	$ 0.63

CONSOLIDATED STATEMENTS OF OTHER COMPREHENSIVE INCOME – US GAAP

For the years ended December 31,	**2007**	2006	2005
Net earnings – US GAAP	$ **128,440**	$ 120,848	$ 83,043
Defined benefit pension plan (Note e)	**67**	–	–
Comprehensive income	$ **128,507**	$ 120,848	$ 83,043

CONSOLIDATED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS) – US GAAP

As at December 31,	2007	2006	2005
Balance, beginning of year	$ (893)	$ –	$ –
Defined benefit pension plan (Note e)	67	(893)	–
Balance, end of year	$ (826)	$ (893)	$ –

CONDENSED CONSOLIDATED BALANCE SHEETS

	2007		2006	
As at December 31,	As Reported	US GAAP	As Reported	US GAAP
Assets				
Cash	$ 8,665	$ 8,665	$ 11,876	$ 11,876
Other current assets	104,544	104,544	130,508	130,508
Property and equipment (Note a)	2,116,834	2,106,073	1,977,062	1,967,135
Goodwill (Note g)	9,933	9,732	7,914	7,914
Other assets (Notes d, e)	291	9,403	14,144	12,160
Deferred risk management loss (Note c)	–	–	3,968	–
Unrealized risk management gain	14,320	14,320	–	–
	$ 2,254,587	$ 2,252,737	$ 2,145,472	$ 2,129,593
Liabilities and shareholders' equity				
Current liabilities	$ 157,357	$ 157,357	$ 153,316	$ 153,316
Long term debt (Note d)	832,188	841,577	852,385	850,526
Asset retirement obligations	36,696	36,696	29,791	29,791
Unrealized risk management loss	1,585	1,585	6,816	6,816
Guarantee obligation (Note f)	–	–	–	873
Unfunded pension liability (Note e)	–	798	–	1,082
Future income taxes (Notes a, e)	293,494	290,203	302,690	297,755
Non-controlling interest (Note f)	63,311	63,311	66,350	65,477
	1,384,631	1,391,527	1,411,348	1,405,636
Capital stock (Note b)	235,871	265,858	231,992	261,979
Contributed surplus	24,233	24,233	16,974	16,974
Retained earnings	609,852	571,945	485,158	445,897
Accumulated other comprehensive income (loss) (Note e)	–	(826)	–	(893)
	869,956	861,210	734,124	723,957
	$ 2,254,587	$ 2,252,737	$ 2,145,472	$ 2,129,593

Notes to the Consolidated Financial Statements

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOW

For the years ended December 31,	2007	2006	2005
Operating activities			
Net earnings	$ 128,440	$ 120,848	$ 83,043
Amortization of deferred charges and other	3,417	1,996	22,940
Depletion and depreciation	152,245	153,964	104,525
Accretion of asset retirement obligations	2,718	2,257	1,975
Unrealized foreign exchange gain	(79,740)	(665)	(7,808)
Future income taxes	(26,619)	(6,323)	53,221
Unrealized risk management (gain) loss	5,467	(29,164)	8,529
Loss on equity investment	159	–	–
Other	10,107	13,392	11,687
Change in non-cash working capital	(23,366)	19,823	6,612
Cash from operating activities	172,828	276,128	284,724
Cash from financing activities	60,725	308,170	172,849
Cash used in investing activities	(236,764)	(581,376)	(458,687)
Change in cash	(3,211)	2,922	(1,114)
Cash, beginning of year	11,876	8,954	10,068
Cash, end of year	$ 8,665	$ 11,876	$ 8,954

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

a) *FULL COST ACCOUNTING*

The full cost method of accounting for crude oil and natural gas operations under Canadian and US GAAP differ in the following respects.

Under US GAAP, an impairment test is applied to ensure the unamortized capitalized costs in each cost centre do not exceed the sum of the present value, discounted at 10%, of the estimated constant dollar, future net operating revenue from proved reserves plus unimpaired unproved property costs less applicable taxes. Under Canadian GAAP, a similar impairment test calculation is performed with the exception that cash flows from proved reserves are undiscounted and utilize forecasted pricing to determine whether impairments exist. If impairment exists, then the amount of the write down is determined using the fair value of reserves. Under SEC regulations, the excess above the ceiling is not expensed if, subsequent to the end of the period, but prior to the release of the financial statements, oil and natural gas prices increase sufficiently such that an excess above the ceiling would have been eliminated if the increased prices were used in the calculation.

The Company has completed an impairment test calculation at December 31, 2007 which indicated an impairment of its oil and natural gas properties of approximately $105 million, net of tax (December 31, 2006 - $52 million). However, natural gas prices subsequent to December 31, 2007 and 2006 improved sufficiently to eliminate this calculated impairment. As a result, the Company was not required to record a write-down of its oil and natural gas properties, in either year, under the full cost method of accounting. Based on spot prices for oil and natural gas as of December 31, 2007, commodity hedges increased the full cost ceiling by $1.1 million (December 31, 2006 - $21.1 million), net of income tax.

Depletion and depreciation on property and equipment is provided using the unit-of-production method under Canadian and US GAAP. Both methods also use proved reserves to determine the rate however, for Canadian GAAP, proved reserves are determined using forecasted prices whereas US GAAP applies constant prices. This reconciliation item resulted in a $0.8 million increase to depletion and depreciation expense for US GAAP purposes during the year ended December 31, 2007 (2006 - $10.9 million, 2005 – $1.0 million decrease).

b) *FUTURE INCOME TAXES*

Under US GAAP enacted tax rates are used to calculate future taxes, whereas Canadian GAAP uses substantively enacted tax rates. The future income tax adjustments included in the reconciliation of net earnings under Canadian GAAP to US GAAP and the balance sheet effects include the effect of such rate differences, if any, as well as the tax effect of the other reconciling items noted.

US GAAP requires flow-through shares be recorded at their fair value without any adjustment for the renouncement of the tax deductions and any temporary difference resulting from the renouncement must be recognized in the determination of tax expense in the year incurred.

The cumulative retained earnings adjustment relating to flow-through shares issued prior to December 31, 2003 was $30.0 million.

The net future income tax liability is comprised of:

As at December 31,	**2007**	2006
Future income tax liabilities		
Property and equipment	**$ 249,552**	$ 227,103
Timing of partnership items	**43,857**	83,328
Foreign exchange gain on long-term debt	**18,340**	8,729
Other	**–**	489
Future income tax assets		
Non-capital losses carried forward	**(5,422)**	–
Attributed Canadian royalty income	**(7,810)**	(7,462)
Asset retirement obligations	**(9,177)**	(8,642)
Other	**(1,201)**	–
Future income taxes	**$ 288,139**	$ 303,545
Net future income taxes	**$ 288,139**	$ 303,545
Current portion, net	**2,064**	(5,790)
Non-current future income taxes	**$ 290,203**	$ 297,755

c) *DERIVATIVE INSTRUMENTS AND HEDGING*

On January 1, 2004, the Company adopted under Canadian GAAP, EIC 128 which required derivatives not designated as hedges to be recorded on the balance sheet as either assets or liabilities at their fair value. Changes in the derivative's fair value are recognized in current period earnings. Under the transitional rules, any gain or loss at the implementation date was deferred and recognized into revenue. At January 1, 2007, the Company adopted the CICA Handbook Section 3855 as disclosed in Note 2 to these consolidated financial statements. Under the new standard the deferred loss amount was reclassified as an adjustment to opening retained earnings, net of tax, without restatement of prior periods. The deferred loss recognized at January 1, 2004 under Canadian GAAP had already been recognized in earnings for US GAAP. As a result, the deferred amount has now been fully recognized in earnings for both Canadian and US GAAP purposes. The Company has not designated any of its financial instruments as hedges for accounting purposes under US or Canadian GAAP.

d) *DEFERRED FINANCING CHARGES*

Under US GAAP, discounts on long-term debt are classified as a reduction of long-term debt. For Canadian GAAP, prior to 2007, discounts were recorded as deferred financing charges. At January 1, 2007, the Company adopted the CICA Handbook Section 3855 as disclosed in Note 2 to these consolidated financial statements. Under the standard, deferred financing charges are classified as a reduction of senior term notes, without restating prior years and the Company began amortizing these costs using the effective interest method.

In 2007, as a result of the adoption of 3855, transaction costs, netted within senior term notes under Canadian GAAP, have been reclassified to other assets to be in compliance with US GAAP.

Notes to the Consolidated Financial Statements

e) DEFINED BENEFIT PENSION PLAN

At December 31, 2006, the Company adopted, for US GAAP purposes SFAS 158, *"Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FIBS Statements No. 87, 88, 106 and 132(R)"*. These amendments require the Company to recognize the over or under funded status of defined benefit pension plans on the balance sheet as either an asset or liability and to recognize changes in the funding status through other comprehensive income. The transitional provisions, on adoption, required an adjustment to the closing balance of accumulated other comprehensive income. Canadian GAAP currently requires recognition of the accrued benefit or liability and does not require the Company to recognize the funded status of the plan on the balance sheet.

f) GUARANTEE

As disclosed in Note 4 to the consolidated financial statements, MPP has guaranteed payment of certain obligations of its limited partner under ...edit agreement between the limited partner and a syndicate of lenders. Canadian GAAP only requires disclosure of this type of financial ...rangement. US GAAP, under FIN 45 *"Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness* ... requires the fair valuation of the guarantee and the inclusion of the liability in the consolidated balance sheets. The offsetting adjustment ...ected as a charge to non-controlling interest.

...alue of the guarantee at December 31, 2007 was estimated to be nil (December 31, 2006 - $873 thousand).

...NESS COMBINATION

...August 15, 2007, the Company closed the acquisition of Stylus as disclosed in Note 3 to these consolidated financial statements. During the ... prior to close, the Company had acquired 3.7% of the issued and outstanding shares of Stylus on the open market. US GAAP requires ...atement of the initial 3.7% to an equity investment from the date of acquisition to the date of consolidation on change of control. ... this standard to the acquisition resulted in a current period charge to earnings of $201 thousand and a corresponding adjustment

...LE AND PAYABLE AMOUNTS

...ecember 31, (in thousands of Canadian dollars)	2007	2006
...ble includes the following:		
...eceivable	$ 3,854	$ 2,234
...interest receivable	16,594	16,295
	56,526	60,663
	3,357	4,343
	$ 80,331	$ 83,535

As at December 31, (in thousands of Canadian dollars)	2007	2006
Accounts payable includes the following:		
Trade payables	$ 34,342	$ 42,976
Royalties payable	5,956	4,728
Accruals	107,215	90,858
Other payables	470	2,881
	$ 147,983	$ 141,443

i) RECENT ACCOUNTING PRONOUNCEMENTS

As at January 1, 2007, the Company adopted, for US GAAP purposes, FASB Interpretation No. 48 *"Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109"*. The interpretation provides clarification and guidance on financial statement recognition and disclosure of uncertain tax positions taken or anticipated in a tax return. The adoption of this standard has had no material impact on the Company's consolidated financial statements.

New and revised accounting pronouncements have been evaluated by the Company and it was determined that the following may have a significant impact on the consolidated financial statements:

i) As of January 1, 2008, the Company will be required to adopt, for US GAAP purposes, SFAS 157 *"Fair Value Measurements"*. The standard provides a common definition of fair value, expands disclosure about fair value measurements, and establishes a methodology for measuring fair value under US GAAP. The Company does not believe that the adoption of this standard should have a material impact on its consolidated financial statements.

ii) As of January 1, 2008, the Company will be required to adopt, for US GAAP purposes, the measurement requirements under SFAS 158, *"Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R)"*. This portion of the amended standard requires the Company to measure the funded status of the plan as of the date of the year-end consolidated financial statements. The Company currently measures the funded status of the plan each year-end and believes there should be no significant impact on its consolidated financial statements due to the adoption of this standard.

iii) As of January 1, 2009, the Company will be required to adopt, for US GAAP purposes, SFAS No. 160, *"Non-controlling Interest in Consolidated Financial Statements, an Amendment of ARB No. 51"*. Under the standard, the non-controlling interest in a subsidiary is to be classified as a separate component of equity. Also, the US consolidated statement of earnings presentation will require net earnings to include the amounts attributable to both the parent and the non controlling interest and to disclose these respective amounts. The Company believes the adoption of the standard should not have a material impact on the consolidated financial statements.

iv) As of January 1, 2009, the Company will be required to adopt for US GAAP purposes, SFAS 141(R), *"Business Combinations"*, which replaces SFAS 141. This revised standard requires assets and liabilities acquired in a business combination, contingent consideration, and certain acquired contingencies to be measured at fair value as of the date of acquisition. Also, transaction costs are to be recognized separately from the business combination. The Company is assessing the impact this standard will have on its consolidated financial statements for all transactions entered into after the effective date.

Supplemental Oil and Natural Gas Information

Supplemental Oil and Natural Gas Information (unaudited)

A) NET PROVED OIL AND NATURAL GAS RESERVES

The net proved oil and natural gas reserve estimates as at December 31, 2007, 2006 and 2005 set forth below were prepared in accordance with guidelines established by the Securities and Exchange Commission and accordingly were based on existing economic and operating conditions. Oil and natural gas prices in effect as of the respective year ends were used without any escalation except in those instances where the sale was covered by contract, in which case the applicable contract price was used. Operating costs, royalties, and future development costs were based on current costs with no escalation.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures. The following reserve data represents estimates only and should not be construed as being exact. Moreover, the present value should not be construed as the current market value of the Company's oil and natural gas reserves or the costs that would be incurred to obtain equivalent reserves. All of the reserves are located in Canada.

ESTIMATED QUANTITIES OF RESERVES

	2007		2006		2005	
Years ended December 31,	**Crude oil & NGL's (mbbls)**	**Natural Gas (mmcf)**	Crude oil & NGL's (mbbls)	Natural Gas (mmcf)	Crude oil & NGL's (mbbls)	Natural Gas (mmcf)
Balance, beginning of year	**27,620**	**553,331**	29,515	455,503	18,771	359,975
Revisions of previous estimates	**2,247**	**14,217**	(1,130)	66,149	5,550	59,930
Extensions, discoveries and other additions	**933**	**48,434**	1,840	74,649	6,498	66,940
Acquisitions of minerals in place	**1,091**	**38,286**	201	10,270	722	5,564
Dispositions of minerals in place	**(8,935)**	**(9,288)**	(229)	(12,939)	–	(56)
Production	**(2,070)**	**(41,999)**	(2,577)	(40,301)	(2,026)	(36,850)
nce, end of year	**20,886**	**602,981**	27,620	553,331	29,515	455,503
ved developed reserves						
Balance, beginning of year	**23,334**	**411,075**	23,827	385,243	15,481	318,177
Balance, end of year	**17,829**	**452,871**	23,334	411,075	23,827	385,243

B) CAPITALIZED COSTS RELATED TO OIL AND NATURAL GAS ACTIVITIES

The aggregate capitalized costs of oil and natural gas activities and costs incurred in oil and natural gas property acquisitions, development, and exploration activities were as follows (excluding MPP):

Capitalized costs

As at December 31, (in thousands of Canadian dollars)	**2007**	2006
Proved properties	**$ 2,444,137**	$ 2,231,401
Unproved properties:		
Acquisition	**159,578**	131,333
Exploration	**153,827**	108,487
Accumulated depletion and depreciation	**(710,076)**	(561,961)
	$ 2,047,466	$ 1,909,260

Costs incurred on unproved properties

		Includes costs incurred in			
As at December 31, (in thousands of Canadian dollars)	**Cumm. 2007**	**2007**	2006	2005	Prior Years
Acquisition	**$ 159,578**	**$ 28,245**	$ 1,843	$ 12,296	$117,194
Exploration	**153,827**	**45,340**	(35,119)	60,368	83,238
	$ 313,405	**$ 73,585**	$ (33,276)	$ 72,664	$200,432

Costs incurred

Years ended December 31, (in thousands of Canadian dollars)	**2007**	2006	2005
Acquisition costs (net of disposition)			
Proved properties	**$ (109,262)**	$ 33,094	$ 28,575
Unproved properties	**28,245**	1,843	12,296
Development costs			
Development of proved undeveloped reserves	**293,335**	304,316	140,504
Other	**(41,550)**	111,773	283,667
Exploration costs	**42,908**	72,448	46,484
Total costs incurred	**$ 213,676**	$ 523,474	$ 511,526

Costs are transferred into the depletion base on an ongoing basis as the undeveloped properties are evaluated and proved reserves are established or impairment determined. Pending determination of proved reserves attributable to the above costs, the Company cannot assess the future impact on the amortization rate.

C) STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS AND CHANGES THEREIN RELATING TO PROVED OIL AND NATURAL GAS RESERVES

The standardized measure of discounted future net cash flows and changes therein relating to proved oil and natural gas reserves ("Standardized Measure") does not purport to present the fair market value of the Company's oil and natural gas properties. An estimate of such value should consider, among other factors, anticipated future prices of oil and natural gas, the probability of recoveries in excess of existing proved reserves and acreage prospects, and perhaps different discount rates. It should be noted that estimates of reserve quantities, especially from new discoveries, are inherently imprecise and subject to substantial revisions. The computation also excludes values attributable to the Company's midstream interests, referred to in the Financial Statements as Mazeppa Processing Partnership.

Under the Standardized Measure, future cash inflows are estimated by applying year end prices, adjusted for contracts currently in place to deliver production to the estimated future production of year end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on year end costs to determine pre-tax cash inflows. Future taxes are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over the Company's tax basis in the associated proved oil and natural gas properties. Tax credits and net operating loss carry forwards are also considered in the future income tax calculation. Future net cash inflows after income taxes are discounted using a 10 percent annual discount rate to arrive at the Standardized Measure.

Supplemental Oil and Natural Gas Information

Years ended December 31, (in thousands of Canadian dollars)	**2007**	2006	2005
Future cash inflows	**$ 5,740,433**	$ 5,253,029	$ 6,571,858
Future production costs	**(2,183,122)**	(1,946,470)	(1,718,793)
Future development costs	**(340,215)**	(339,699)	(209,901)
Future net cash flows	**3,217,096**	2,966,860	4,643,164
Income taxes	**(518,136)**	(519,798)	(1,344,684)
Total undiscounted future net cash flows	**2,698,960**	2,447,062	3,298,480
10 percent annual discount for estimated timing of cash inflows	**(1,340,535)**	(1,185,942)	(1,726,975)
Standardized measure of discounted future net cash flows	**$ 1,358,425**	$ 1,261,120	$ 1,571,505

The Company estimates that it will incur $177.6 million in 2008, $97.1 million in 2009 and $18.6 million in 2010 to develop proved undeveloped reserves.

The following table sets forth an analysis of changes in the standardized measure of discounted future net cash flows from proved oil and natural gas reserves:

Years ended December 31, (in thousands of Canadian dollars)	**2007**	2006	2005
Beginning of year	**$ 1,261,120**	$ 1,571,505	$ 752,878
Sales of production, net of production costs	**(286,961)**	(291,896)	(336,711)
Net change in sales prices, net of production costs	**18,800**	(731,330)	614,690
Extensions, discoveries and additions	**117,276**	183,795	354,186
Changes in estimated future development costs	**202**	(221,882)	(135,499)
Development costs incurred during the period which reduced future development costs	**281,269**	314,251	353,740
Revisions in quantity estimates	**58,269**	(74,504)	526,474
Accretion of discount	**144,449**	215,170	75,288
Purchase of reserves	**116,362**	(23,176)	(7,749)
Sales of reserves	**211,215**	47,220	87
Net change in income tax	**9,411**	396,818	(331,850)
Changes in production rates (timing) and other	**(572,987)**	(124,851)	(294,029)
Standardized measure, end of year	**$ 1,358,425**	$ 1,261,120	$ 1,571,505

Head Office

COMPTON PETROLEUM CORPORATION
Fifth Avenue Place, East Tower
Suite 3300, 425-1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
Telephone: (403) 237-9400
Fax: (403) 237-9410

Email:
investorinfo@comptonpetroleum.com
Website: www.comptonpetroleum.com

Directors

M.F. BELICH, Q.C. [1 2 6]
Chairman,
Compton Petroleum Corporation

J.S. ALLAN, F.C.A., ICD.D
Consultant, RSM Richter LLP

I.J. KOOP, P.Eng. [3]
Independent Businessman

J.W. PRESTON
Independent Businessman

J.T. SMITH, P.Geol. [4]
Independent Businessman

J. A. THOMSON, C.A. [5]
Independent Businessman

E.G. SAPIEHA, C.A.
President & C.E.O.,
Compton Petroleum Corporation

1 *Chairman, Board of Directors*
2 *Chairman, Corporate Governance Committee*
3 *Chairman, Human Resources, Compensation, Environmental, Health and Safety Committee*
4 *Chairman, Engineering, Reserves and Operations Committee*
5 *Chairman, Audit, Finance and Risk Committee*
6 *Chairman, Special Committee of the Independent Members of the Board*

Executive

E.G. SAPIEHA, C.A.
President & C.E.O.

M.J. STODALKA, P.Eng.
VP Operations & Engineering

M.R. JUNGHANS, P.Geol.
VP Exploration

N.G. KNECHT, C.A.
VP Finance & C.F.O.

T.G. MILLAR, LL.B.
VP General Counsel
& Corporate Secretary

G.J. FOLLENSBEE, P.Eng.
VP Engineering Exploitation

R.W.P. SYMONDS, P.Eng.
VP Foothills
& Corporate Development

Banking Syndicate

BANK OF MONTREAL
BANK OF NOVA SCOTIA
TORONTO-DOMINION BANK
SOCIÉTÉ GÉNÉRALE
JPMORGAN CHASE
MORGAN STANLEY
CREDIT SUISSE

Independent Reserve Engineers

NETHERLAND, SEWELL & ASSOCIATES, INC.

Legal Counsel

FRASER MILNER CASGRAIN LLP
STIKEMAN ELLIOTT LLP

Auditors

GRANT THORNTON LLP

Transfer Agent and Registrar

COMPUTERSHARE TRUST COMPANY OF CANADA
600, 530-8 Ave. S.W.
Calgary, Alberta,
Canada AB T2P 3S8

Stock Exchange Listings

THE NEW YORK STOCK EXCHANGE
Trading symbol: CMZ

THE TORONTO STOCK EXCHANGE
Trading symbol: CMT

COMPTON PETROLEUM CORPORATION 2007 ANNUAL REPORT

COMPTON PETROLEUM CORPORATION

Fifth Avenue Place, East Tower
Suite 3300, 425-1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
Telephone: (403) 237-9400
Fax: (403) 237-9410

Email: investorinfo@comptonpetroleum.com
Website: www.comptonpetroleum.com